Air Quality Permitting
Statement of Basis

May 19, 2004

Tier II / Permit to Construct No. T2-030514

Blaine Larsen Farms, Dehydration Division, Dubois

Facility ID No. 033-00002

Prepared by:

Ken Hanna, Permit Writer
AIR QUALITY DIVISION

FINAL PERMIT

Acronyms, Units, and Chemical Nomenclatures

AAC	Annual Ambient Concentration for non-carcinogens
AACC	Acceptable Ambient Concentrations for carcinogens
AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
BLF	Blaine Larsen Farms
Btu	British thermal unit
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
EPA	Environmental Protection Agency
gr	grain (1 lb = 7,000 grains)
HAPs	Hazardous Air Pollutants
IDAPA	A numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
lb/hr	pound per hour
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
NESHAP	Nation Emission Standards for Hazardous Air Pollutants
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	Prevention of Significant Deterioration
PTC	permit to construct
Rules	*Rules for the Control of Air Pollution in Idaho*
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
TAPs	toxic air pollutants
T/yr	tons per year
UTM	Universal Transverse Mercator
VOC	volatile organic compound

1. PURPOSE

The purpose for this memorandum is to satisfy the requirements of IDAPA 58.01.01 Sections 201 and 404.04, *Rules for the Control of Air Pollution in Idaho* (Rules) for Tier II operating permits and Permits to Construct.

2. FACILITY DESCRIPTION

The Blaine Larsen Farms, Inc. Dehydration Division (Larsen Farms) processes dehydrated potato products at the facility located near Hamer, Idaho. The process primarily involves potato dehydration to make potato flakes. Potatoes are cleaned, peeled, cooked and sized prior to being transferred into a drying unit. The main sources of emissions include a boiler, dryers, dehydration lines, pneumatic material transfer equipment and packaging lines. Some dryers are of the direct-fired type and some use steam from the boiler.

3. FACILITY / AREA CLASSIFICATION

Larsen Farms is a major facility for purposes of the Title V program as defined under IDAPA 58.01.01.008.10 because the actual or potential emissions of SO_2 and NO_x exceed 100 tons per year. Larsen Farms is not a major facility for purposes of the PSD/NSR program as defined under IDAPA 58.01.01.205.01 (40 CFR 52.21(b)(1)). The AIRS classification is "A."

The Larsen Farms facility is located within AQCR 61, UTM zone 12 and Clark County. The area is classified as attainment or unclassifiable for all federal and state criteria air pollutants. The SIC is 2034 which represents establishments primarily engaged in artificially dehydrating fruits and vegetables, including "potato flakes, granules, and other dehydrated potato products."

The AIRs information provided in Appendix C provides the classification information for each regulated air pollutant at Larsen Farms. This required information is entered into the EPA AIRs database.

4. APPLICATION SCOPE

On May 19, 2003, DEQ received an application from Larsen Farms to obtain a facility-wide combination Tier II operating permit and permit to construct (PTC) for the existing Dehydration Division facility. The purpose of this permit is twofold: 1) it will address Tier II and PTC requirements for construction projects which required a PTC but did not obtain one prior to construction, and; 2) it will address PTC requirements for a proposed Boiler modification to burn no. 6 fuel oil. For purposes of addressing the PTC requirements, each construction project following the initial construction project represents a "modification" to the Larsen Farms facility. The specific construction projects/modifications which are addressed by this permitting action are described as follows:

Initial Construction:	Initial construction of the facility in 1989.
Modification Project 1:	Construction of a Dryer system in 1990.
Modification Project 2:	Boiler fuel system modification in 1992.
Modification Project 3:	Construction of Flake Packaging Torit Line and replacement of the boiler in 1996.
Modification Project 4:	Construction of 12 Drum Dryers and a Flake Packaging system in 1997.
Modification Project 5:	Construction of a fluidized bed Dryer system in 1998.
Proposed Modification Project:	Modify Boiler system to burn no. 6 "very low sulfur oil."

4.1 Application Chronology

May 19, 2003	DEQ received a facility-wide permit application for the Larsen Farms facility.
August 29, 2003	Application declared incomplete.
October 1, 2003	DEQ received additional permit application information.
October 31, 2003	DEQ received additional permit application information.
November 10, 2003	Permit application declared complete.
December 3, 2003	DEQ received additional permit application information.
December 16, 2003	DEQ received additional permit application information.
January 16, 2004	DEQ received additional permit application information.
March 5, 2004	DEQ issued a draft permit to Larsen Farms for review.
March 9, 2004	DEQ received comments from Larsen Farms regarding the draft permit.
May 17, 2004	DEQ received additional requested information for the PSD non-applicability analysis.

5. PERMIT ANALYSIS

This section of the Statement of Basis describes the regulatory requirements for this Tier II/PTC action.

5.1 Emissions Inventory and Equipment Listing

Refer to Appendix A to see the emissions inventory technical memorandum. The equipment listing and emissions inventory for criteria pollutants from the Larsen Farms Dehydration facility is summarized in Table 5.1. The facility-wide inventory of "controlled emission rates" for the toxic air pollutants (TAPs) which have estimated emission rates above the screening emission levels (EL) is given in Table 5.2. Note that although the permit application indicates estimated PAH emissions exceed the EL, the DEQ analysis determined that it doesn't, therefore, PAHs are not in Table 5.2. This inventory summarizes the total facility emissions allowed by the Tier II/PTC, and it accounts for emissions from all of the following: the initial construction project, modification projects 1 – 5, and the proposed modification project.

Table 5.1 SUMMARY OF EMISSIONS INVENTORY

Blaine Larsen Farms, Dubois
Potential Emissions – Hourly (lb/hr), and Annual (T/yr)

Source Description	CO		NO_x		PM_{10}		SO_2		VOC	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Boiler, Wabash Power Equipment	11.9	51.9	41.8	146	8.29	29.0	69.8	244	1.14	3.98
Dryer Process, Maxon, Fluidized Bed Type	0.38	1.66	0.67	2.94	0.76	3.33	0.08	0.38	0.02	0.11
Dryer Process, National, Stages A1, A2, B, C	1.2	5.3	2.2	9.6	3.9	16.9	0.32	1.4	0.08	0.36
Dryer Process, Flaker/Drum Type, No. 1 through 12	---	---	---	---	3.5	15.4	0.12	0.48	---	---
Flake Packaging Bulk Line	---	---	---	---	0.065	0.28	---	---	---	---
Flake Packaging	---	---	---	---	0.032	0.14	---	---	---	---
Flake Packaging Torit	---	---	---	---	0.43	1.88	---	---	---	---
Flake Packaging Drum Negative Air Baghouse	---	---	---	---	0.097	0.42	---	---	---	---
Two 30,000 gallon fuel oil storage tanks	---	---	---	---	---	---	---	---	---	0.09
Propane Heater Numbers 1, 2 and 3, Maxon	0.30	1.32	0.68	3.00	0.03	0.12	0.06	0.26	0.02	0.09
Total Emissions	**13.8**	**60.2**	**45.4**	**162**	**17.1**	**67.5**	**70.4**	**247**	**1.3**	**4.6**

Table 5.2 SUMMARY OF FACILITY-WIDE TAP EMISSION INVENTORY (CONTROLLED)

TAP	Emission Rate (lb/hr)	EL (lb/hr)
Arsenic	1.18E-03	1.5E-06
Beryllium	4.32E-04	2.8E-05
Cadmium	4.57E-04	3.7E-06
Chromium (6+)	2.20E-04	5.6E-07

5.2 *Modeling*

Refer to Appendix B to see the air dispersion modeling technical memorandum. The modeling conducted for this facility was based on the emissions inventory described directly above. The modeling demonstrates that emissions from the facility would not cause or significantly contribute to a violation of any ambient air quality standard under IDAPA 58.01.01.203.02 or any TAP standards under IDAPA 58.01.01.210. Summaries of the modeling results for the facility is provided in Tables 5.3 and 5.4.

Table 5.3 FULL IMPACT ANALYSIS RESULTS

Pollutant	Averaging Period	Total Ambient Impact[a] ($\mu g/m^3$)[b]	Background Concentration ($\mu g/m^3$)	Total Ambient Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
SO_2	Annual	24.2	8	32.2	80	40
	24-hour	269	26	295	365	81
	3-hour	703	34	737	1300	57
NO_2	Annual	27	17	44	100	44
PM_{10}[c]	Annual	21	26	47	50	93
	24-hour	74	73	147	150	98
CO	8-hour	---	---	---	40,000	insignificant
	1-hour	---	---	---	10,000	insignificant

a. Impact from facility-wide emissions
b. Micrograms per cubic meter
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10})

Table 5.4 TAP IMPACT ANALYSIS RESULTS

IDAPA 58.01.01.586			
Pollutant	**Highest Annual Impact ($\mu g/m^3$)**	**AACC ($\mu g/m^3$)**	**Percent of AACC**
Arsenic	1.2E-04	2.3E-04	52
Beryllium	4.0E-05	4.2E-03	1
Cadmium	1.2E-04	5.6E-04	21
Chromium VI	2.0E-05	8.3E-05	24
Formaldehyde	8.5E-03	7.7E-02	11
Nickel	1.7E-04	4.2E-03	4
IDAPA 58.01.01.585			
Pollutant	**Highest 24-Hour Impact ($\mu g/m^3$)**	**AAC ($\mu g/m^3$)**	**Percent of AAC**
Cobalt	0.011	2.5	0.5
Phosphorous	0.017	5	0.3
Vanadium	0.050	2.5	2

As shown in Table 5.4, the dispersion modeling demonstrated that TAP emissions from all sources at the facility would not result in modeled concentrations at the maximum impacted receptor exceeding the applicable standards in IDAPA 58.01.01.585 and 586.

5.3 *Regulatory Review*

This section describes the regulatory analysis of the applicable air quality rules with respect to this Tier II/PTC.

IDAPA 58.01.01.201 .... Permit to Construct Required

The facility was constructed and modified without first obtaining PTCs, therefore a PTC is required.

IDAPA 58.01.01.203.03.02 .... Demonstration of Preconstruction Compliance with NAAQS

Compliance with the NAAQS has been demonstrated in the permit application. Refer to the modeling section above and Appendix B for details.

IDAPA 58.01.01.203.03 and 210 .... Demonstration of Preconstruction Compliance with Toxic Standards

Toxic air pollutants (TAP) are emitted from the facility as a result of fuel combustion in the Boiler, process units, and heaters. Since the Idaho TAP standards became effective on June 30, 1995, these rules apply only to sources constructed or modified after that date. To determine the specific sources and modifications to which the TAP rules apply, refer to the list of "projects" provided in the "Project Scope" section of this document. It is apparent from the list that the TAP rules apply to all projects listed except for the initial facility construction project in 1989 and Modification Projects 1 and 2 (the 1990 Dryer system installation and the 1992 boiler fuel modification). For each modification project after June 30, 1995, the TAP rules apply only to the increase in TAP emissions associated with that particular modification.

For the TAPs analysis, Larsen Farms has taken a conservative approach in the permit application by evaluating "total" emissions from the facility, based on each emissions unit's maximum rated capacity, not just the increase in emissions associated with each modification project. Based on this conservative estimate, it has been demonstrated that the facility was constructed to be in compliance with the requirements of IDAPA 58.01.01.203.03 and 210. Details of the emissions estimates are provided in Appendix A, details of the modeling analysis are provided in Appendix B, and the results are summarized below.

The TAP emission estimates and analysis provided in the application are based on controlled emission rates (because of the boiler fuel throughput limits) and controlled ambient concentrations. To estimate the "uncontrolled" pound per hour TAP emission rates two steps were taken. First, the maximum fuel throughput to the boiler was determined to be 960 gal/hr for #6 fuel oil, based on information in the application (144 MMBtu/hr ÷ 150,000 Btu/gal = 960 gal/hr). Second, the controlled TAP emission rates in Table 7-1 (i.e., Table 0-1) of Section 7 of the application, as received by DEQ on January 16, 2004, were multiplied by a factor of 1.08 [(960 gal/hr) / (889 gal/hr) = 1.08]. For example, for arsenic the "controlled emission rate" in Table 7-1 is 1.18E-03 lb/hr and the "uncontrolled emission rate" is 1.27E-03 lb/hr [(1.18E-03 lb/hr)(1.08) = 1.27E-03 lb/hr]. This approach is conservative since the emission rates of all emission units, not just the boiler (note that the boiler is the only unit with a higher fuel throughput), are increased to determine the uncontrolled rates. On this basis, it is apparent that the TAPS listed above in Table 5.2 are the only TAPs with "uncontrolled emission rates" that exceed the ELs. To determine the uncontrolled ambient concentrations of the TAPs listed in Table 5.2, the same approach is taken by multiplying the controlled modeled concentrations in Table 7-2 (i.e., Table 0-2) of Section 7 of the application, as received by DEQ on January 16, 2004, by the factor of 1.08. For example, for arsenic, the model and Table 7-2 show the "controlled ambient concentration" is 1.2E-04 $\mu g/m^3$ based on a boiler fuel oil throughput of 889 gal/hr, and the "uncontrolled ambient concentration" is 1.29 $\mu g/m^3$ [(1.2E-04 $\mu g/m^3$)(1.08) = 1.29E-04 $\mu g/m^3$], based on the maximum fuel throughput of 960 gal/hr.

Conclusion: On this basis, it is apparent that most of the TAPs from fuel combustion (including PAHs) were shown to be in compliance with IDAPA 58.01.01.210.05 since the source's or modification's uncontrolled hourly emissions rate would be less than the applicable screening emission level listed in Sections 585 and 586. The remaining TAPs, which are listed in Table 5.2 above, were shown to be in compliance with IDAPA 58.01.01.210.06 since the source's or modification's uncontrolled ambient concentration at the point of compliance is less than or equal to the applicable acceptable ambient concentration.

Since vanadium was not included in the TAPs analysis, the following is provided based on information from the application. From Appendix A, the estimated controlled emission rate of vanadium is 2.83E-02 lb/hr. The estimated uncontrolled emission rate from the Boiler would be 3.05 E-02 lb/hr [(2.83E-02 lb/hr)(1.08) = 3.05E-02 lb/hr]. This exceeds 3E-03 lb/hr, the screening emission level in IDAPA 58.01.01.585, therefore, the uncontrolled ambient concentration needs to be estimated for comparison with the AAC. Assuming a straight line relationship between the emission rates and the modeled concentrations, and using the information for cobalt on Tables 7-1 and 7-2 (i.e., Tables 0-1 and 0-2) of Section 7 of the application, as received by DEQ on January 16, 2004, the estimated maximum concentration of vanadium is determined as follows:

cobalt uncontrolled emission rate:	(5.35E-03 lb/hr)(1.08) = 5.78E-03 lb/hr
cobalt uncontrolled ambient concentration:	(0.0094 $\mu g/m^3$)(1.08) = 0.0102 $\mu g/m^3$

(0.0102 $\mu g/m^3$)/(5.78E-03 lb/hr) = (x)/(3.05E-02 lb/hr)

x = vanadium uncontrolled ambient concentration = [(3.05E-02)/(5.78E-03)][0.0102 $\mu g/m^3$]
x = 0.054 $\mu g/m^3$

Since the estimated uncontrolled ambient concentration is less than 2.5 $\mu g/m^3$, the AAC for vanadium, the requirements of IDAPA 58.01.01.210.06 are met.

IDAPA 58.01.01.205, 40 CFR 52 .... Permit Requirements for New Major Facilities or Major Modifications in Attainment or Unclassifiable Areas; PSD

Larsen Farms is not a major facility for purposes of the NSR/PSD program as defined under IDAPA 58.01.01.205.01 [40 CFR 52.21(b)(1)(i)(a), (b) and (c)] because:

> The facility has the potential to emit more than 100 tons per year of any regulated NSR pollutant, however, it is not on the list of stationary sources specified in 40 CFR 52.21(b)(1)(i)(a);
>
> Notwithstanding the stationary source size specified in 40 CFR 52.21(b)(1)(i), the stationary source will not emit, or have the potential to emit, 250 tons per year or more of a regulated NSR pollutant; or
>
> Any physical change that would occur at the stationary source not otherwise qualifying under 40 CFR 52.21(b)(1), as a major stationary source, will not constitute a major stationary source by itself.

Based on an analysis of the initial facility construction project, modification projects 1-5, and the requested boiler fuel modification project, none of these projects undertaken by Larsen Farms have made the overall facility a "major facility" under the NSR/PSD program at any point in the past, nor will it be after issuance of this Tier II permit. Details are provided below. In addition, none of the modification projects were a "major modification" for purposes of the NSR/PSD program. This is because a facility must first be classified as a "major facility" before the major modification definition given by 40 CFR 52.21(b)(2) can be applied.

An emission analysis to address past applicability of the PSD rules was received by DEQ on December 3, 2003. To further clarify the analysis, DEQ received additional requested details on May 17, 2004 and a copy is included in Appendix A. This information was reviewed and found to be consistent with DEQ methods and procedures. Details are provided below for SO_2 and NO_x since these are the only two pollutants with a potential to emit (PTE) near the 250 TPY threshold. It is important to note that the PTE for the initial facility construction project and Modification Projects 1-5 (i.e., all projects constructed without a PTC) is based on the facility's physical and operational design, and it includes credit for no other limitations on the capacity of the facility to emit unless noted otherwise below.

<u>Initial Facility Construction in 1989</u>

Emission Units: The PTE for the initial facility construction project is based on the following equipment which was installed in 1989:

Two Babcock & Wilcox (B&W) boilers. Both boilers were 8 years old when installed at Larsen Farms and capable of firing with residual oil. Both boilers were rated at 30,000 lb/hr, and the maximum capacity is 36 MMBtu/hr based on steam operating parameters of 120 psi, 350° F and a corresponding enthalpy of 1196 BTU/lb.

Four used drum dryers which required a maximum of 4,000 lb/hr of steam per dryer. One cooker was also installed which was heated with flash steam from the drum dryers and no steam directly from the boilers.

One steam peeler which required a maximum of 2,00 lb/hr of steam.

Additional equipment installed included three 1.2 MMBtu/hr propane heaters, the Flake Packaging Line, and the Flake Packaging Bulk Line. None of these emission units required steam from the boilers.

PTE: The physical and operational design of the facility at this time placed a maximum worst case demand on the B&W boilers of 21.5 MMBtu/hr. This was based on a maximum steam utilization rate of 18,000 lb/hr of steam [(18,000 lb/hr)(1196 Btu/lb) = 21,528,000 Btu/hr]. The uncontrolled PTE for the facility was then determined based on this physical and operational design, assuming use of the worst case boiler fuel (no. 6 residual oil) and operations of 8760 hr/yr. Larsen Farms' uncontrolled PTE following this initial construction project was:

	SO_2	NO_x
PTE Change	---	---
Facility-Wide PTE	168	37

<u>Modification Project 1 in 1990</u>

In 1990 the National Dryer was installed. This dryer has 3.6 MMBtu/hr burners that are fired with propane or natural gas, and it did not increase the demand for steam from the boilers. The PTE change associated with this project was:

	SO_2	NO_x
PTE Change	+ 1.0	+ 9.6
Facility-Wide PTE	169	46

Modification Project 2 in 1992

In 1992, the B&W boilers were modified so they could only burn propane. After this conversion it wasn't physically possible to burn oil, therefore, oil was no longer used for determining the PTE. The PTE change associated with this project was:

	SO_2	NO_x
PTE Change	- 165	- 9.7
Facility-Wide PTE	3.2	36

Modification Project 3 in 1996

In 1996, the Wabash Power Equipment Co. boiler was installed and the steam pipes were changed such that it was no longer physically possible to use the two B&W boilers. In addition, the Flake Packaging Torit Line, a material handling system, was installed. The Wabash boiler was new (not used) with a rated capacity of 144 MMBtu/hr, and it was capable of being fired only with propane or natural gas. From this point forward, the PTE was determined using a more conservative approach which was based on the rated capacity of the Wabash boiler (144 MMBtu/hr), with propane or natural gas-firing, and 8760 hr/yr. Note that from this point forward, emissions from the two B&W boilers are no longer included in the PTE for this facility. The PTE change associated with this project was:

	SO_2	NO_x
PTE Change	+ 8.7	+ 111
Facility-Wide PTE	12	147

Modification Project 4 in 1997

In 1997, the four drum dryers installed in 1989 were removed and 12 new drum dryers were installed. In addition the Flake Packaging Drum Negative Air Baghouse Line was installed. The drum dryers are heated with steam from the boiler, and they don't have separate burners. Note that the increased amount of steam required from the Boiler as a result of this project did not change the PTE because the PTE was already based on the rated capacity of the boiler. The PTE change associated with this project was:

	SO_2	NO_x
PTE Change	0	0
Facility-Wide PTE	12	147

Modification Project 5 in 1998

In 1998, the Fluidized Bed Dryer was installed. This dryer has a 4.5 MMBtu/hr burner that is fired with propane or natural gas. The PTE change associated with this project was:

	SO_2	NO_x
PTE Change	+ 0.3	+ 2.9
Facility-Wide PTE	12	150

Currently Requested Boiler Fuel Modification

In the Tier II/PTC permit application, Larsen Farms has requested to modify the Wabash Boiler so it may burn "very low sulfur" residual oil. After issuance of the permit, the PTE for Larsen Farms will be based on the federally enforceable limits specified in the Tier II/PTC, as given below:

	SO_2	NO_x
PTE Change	+ 235	+ 12
Facility-Wide PTE	247	162

Based on this new PTE, NSR/PSD will not apply to Larsen Farms because the PTE for any regulated pollutant will be limited to less than 250 TPY by federally enforceable conditions in the Tier II/PTC permit. In particular, SO_2 is the pollutant which will have the highest allowable emissions, and the PTE will be 247 TPY. The permit will limit the boiler to 244 TPY and all other production processes will be limited to 3 TPY of SO_2.

IDAPA 58.01.01.676-677 .... Fuel Burning Equipment - Particulate Matter

Compliance with the fuel burning equipment standards for PM has been demonstrated. For purposes of this section of the rules, all fuel burning equipment at the Larsen Farms facility are considered to have commenced operation after October 1, 1979. IDAPA 58.01.01.676 applies to the Boiler since the input heat capacity is over 10 MMBtu/hr. IDAPA 58.01.01.677 applies to each dryer and each propane heater since the input heat capacity of each emission unit is less than 10 MMBtu/hr. It is noted that for gas and liquid fuels, the requirements of IDAPA 58.01.01.676 and 677 are identical: for gas the standard is 0.015 grains per dry standard cubic feet (gr/dscf) and for liquid it is 0.050 gr/dscf, both corrected to an oxygen content of 3%. Calculations of PM emissions at 3% oxygen were performed by the applicant based on all allowable fuels and the maximum allowable firing rates. The results are provided on page 52 of the application. The calculations were reviewed and found to be consistent with DEQ methods and procedures. See the emission inventory technical memorandum in Appendix A for details.

Compliance may be demonstrated by operating the boiler in accordance with the NSPS conditions, particularly those regarding the particulate matter standards, and by firing only natural gas or propane in the dryers and propane heaters.

IDAPA 58.01.01.700-703 .... Particulate Matter – Process Weight Limitations

Compliance with the PM process weight limitations has been demonstrated in the permit application, as amended on December 15, 2003, and the results are summarized on page 51. Since the process weight rates used on page 51 were different than the values provided on the revised Tier II/PTC application forms on pages 28-33A, the allowable emissions were recalculated, using Larsen Farms' certified data, and the results are included in Appendix A. The estimated emissions are well below the allowable emission rates.

40 CFR 60 Subpart Db .... New Source Performance Standards (NSPS) for Industrial, Commercial and Institutional Steam Generating Units

40 CFR 60.40b(a), Applicability. Larsen Farms has indicated the Boiler was new when installed, therefore, for purposes of assessing applicability of this subpart it was "constructed" in 1996. When installed, the Boiler was also capable of firing both distillate and residual fuel oil, however, the tanks, piping and other ancillary equipment necessary for firing distillate oil will not be installed until after the Tier II/PTC is issued. On this basis, the Boiler is an "affected facility" under Subpart Db because it is a "steam generating unit that commenced construction, modification, or reconstruction after June 19, 1984 and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 MMBtu/hr)."

60.41b, Definitions. *Very Low Sulfur Oil* means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input.

60.42b, Standard for Sulfur Dioxide. Percent reduction requirements and an emission limit are specified by 60.42b(a). The emission limit equation reduces to simply: Es = (KbHb)/Hb = Kb = 0.80 lb/MMBtu (340 ng/J) since coal is not used. The permit application analyses for the Boiler are based on fuel oil that will not exceed 0.5% sulfur by weight, therefore, a condition was added to the permit which establishes this as a limit. Therefore, it is noted that all fuel oil used by the facility will meet the definition of "*Very low sulfur oil*" as defined by 60.41b. For this fuel oil, compliance is shown below with the emission limit specified by 60.42b(a), based on the AP-42 emission factor in Table 1.3-1 for no. 6 residual oil:

$$SO_2 = [(157)(0.5) \text{ lb/1000 gal}] \times [1000 \text{ gal/150 MMBtu}] = 0.52 \text{ lb/MMBtu}$$

Since only "very low sulfur oil" will be combusted, Larsen Farms has the option of complying with 60.42b(j). This rule specifies the percent reduction requirements [of 60.42b(a)] are not applicable, and the facility must demonstrate that the oil meets the definition of very low sulfur oil by: "(1) Following the performance testing procedures in 60.45b(c) or 60.45b(d), and following the monitoring procedures as described in 60.47b(a) or 60.47b(b) to determine the SO_2 emission rate or fuel oil sulfur content; or (2) maintaining fuel receipts as described in 60.49b(r)." Note that 60.49b(r) refers explicitly to oil that "meets the definition of distillate oil as defined in 60.41b." Therefore, it appears that if very low sulfur "residual" oil is used it may not be acceptable to maintain "fuel receipts" in accordance with 60.49b(r) and, therefore, the testing and monitoring requirements of 60.42b(j)(1) would apply. DEQ requested clarification about this requirement from EPA Region 10 on April 6, 2004. Future compliance with the requirements of 60.42b, 60.45b, 60.47b, and 60.49b should be based on the applicability information provided by EPA, and the permit was written to accommodate this action. Based on the outcome of the forthcoming letter, it is suggested that the permittee maintain a copy of the EPA letter along with the permit for future reference, and that a specific reference be placed on any reports and records that are affected by the letter.

Per 60.42b(e), "compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis." "The SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction in accordance with 60.42b(g). Credits for fuel pretreatment given by 60.42b(h) do not apply because 60.42b(c) does not apply. The following requirements in this section do not apply: 60.42b(b), (c), (d), (f), (h), and (i).

60.43b, Standard for Particulate Matter. On and after the date on which the initial performance test is completed or is required to be completed under 60.8, which ever date comes first, emissions from the boiler must not exceed 20% opacity (six-minute average), except for one six-minute period per hour of not more than 27% opacity in accordance with 60.43b(f). This opacity standard applies at all times, except during periods of startup, shutdown, and malfunction per 60.43b(g). The following requirements of this section do not apply: 60.43b(a) through 60.43b(e).

60.44b, Standard for NO_x. The NO_x standards of 60.44b(a) apply. In the comments DEQ received from Larsen Farms on March 9, 2004, it was indicated that the heat release rates for the boiler are: 77,600 Btu/hr-ft^3 for natural gas; 73,900 Btu/hr-ft^3 for diesel fuel oil; and 73,400 Btu/hr-ft^3 for no. 6 fuel oil. On this basis, the Wabash Boiler has a "high heat release rate" as defined by 40.41b since the heat release rate is greater than 70,000 Btu/hr-ft^3. The NO_x standards apply at all times including periods of startup, shutdown, or malfunction, and compliance shall be determined on a 30-day rolling average per 60.44b(h) and (i). The NO_x standards of 60.44b(b) do not apply because Larsen Farms has stated in the comments received by DEQ on March 9, 2004 that the mixtures will not be combusted simultaneously in the Boiler.

60.44b(l) does not apply since the boiler was constructed prior to July 9, 1997. The following requirements of this section do not apply: 60.44b(b) through 60.44b(g), and 60.44b(j), (k) and (l).

60.45b, Compliance and Performance Test Methods and Procedures for SO_2. The requirements of 60.45b may not be applicable per 60.45b(j); refer to the information provided above for 60.42b regarding the April 6, 2004 information request sent to the EPA. Until the EPA provides further clarification, the specific requirements in this section which apply are 60.45b(a), 60.45b(b), 60.45b(c), 60.45b(f), 60.45b(g), 60.45b(h) and 60.45b(j). As noted, in accordance with 40 CFR 60.45b(j), if the facility combusts very low sulfur oil, it is not subject to the compliance and performance testing requirements of 40 CFR 60.45b if the owner or operator obtains fuel receipts as described in 40 CFR 60.49b(r). It is important to note that EPA has identified typographical errors in 60.45b (see Applicability Determination Index document, Control Number NN06, in Appendix A). EPA provides the following correction: "Section 60.45b(c)(3)(ii) should reference Section 60.45b(c)(3)(i) [not 60.45b(b)(3)(i)]. Section 60.45b(c)(4) and Section 60.45b(c)(5) should reference Section 60.45b(c)(3) [not 60.45b(b)(3)]." The following requirements of this section do not apply: 60.45b(d), 60.45b(e), and 60.45b(i).

60.46b, Compliance and Performance Test Methods and Procedures for PM and NO_x. Specific requirements in this section which apply to PM are the requirements to use method 9 to show compliance with the opacity standards in 60.43b, and this includes 60. 46b(a), 60.46(d), and 60.46b(d)(7). The specific requirements which apply to NO_x are 60.46b(a), 60.46b(c), 60. 46b(e)(1), 60.46b(e)(2), 60.46(e)(4), and 60.46b(e)(5). For distillate oil, and for residual oil as described on page 19 of the application where the fuel nitrogen content is less than 0.3%, 60.46b(e)(4) will apply. If the residual fuel oil supplier is changed in the future, it is possible that 60.46b(e)(2) may become applicable, depending on the actual nitrogen content of the fuel. It is important to note that the EPA has identified a typographical error in 60.46b(e)(5) (see Applicability Determination Index document, Control Number NN06, in Appendix A). The correct version of this requirement is: "If the owner or operator of an affected facility which combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in 60.49b(e), the requirements of paragraph (2) [not iii] of this section apply and the provisions of paragraph (4) [not iv] of this section are inapplicable." The following requirements of this section do not apply: 60.46b(b), 60.46b(d)(1) through 60.46(d)(6), 60.46b(e)(3), 60.46b(f). 60.46b(g), and 60.46b(h).

60.47b, Emission Monitoring for SO_2. . The requirements of 60.47b(f) may not be applicable per 60.45b(j); refer to the information provided above for 60.42b regarding the April 6, 2004 information request sent to the EPA. Until the EPA provides further clarification, the requirements of this section for installation and operation of a CEMS will apply to the Boiler. As noted, 60.47b(f) states that the owner or operator of an affected facility that combusts very low sulfur oil is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in 40 CFR 60.49b(r).

60.48b, Emission Monitoring for PM and NO_x. The opacity standards of 60.43b(f) and (g) apply, therefore the requirements of 60.48b(a) for installation of a continuous opacity monitoring system apply. With regard to NO_x, the monitoring requirements specified by 60.48b(g) apply since the boiler heat input capacity is less than 250 MMBtu/hr and it will have an annual capacity factor greater than 10% for "residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels." Therefore, one of the following options must be met per 60.48b(g):

- Install and operate a continuous monitoring system for measuring NO_x emissions per 60.48b(b) through 60.48b(f), or
- Submit a plan to DEQ monitoring boiler operating conditions and "predicting" NO_x emission rates pursuant to 60.49b(c).

The following requirements of this section do not apply: 60.48b(b)(2), 60.48(e)(1), 60.48b(h), and 60.48b(i).

60.49b, Reporting and Recordkeeping Requirements. All paragraphs of this section apply to the Larsen Farms Boiler except as noted below. Although the detailed requirements of 60.49b(c)(1), (2),and (3) were not printed in the permit, the requirement to comply with these requirements was included in a permit condition under 60.49b(c) as a viable future option. Compliance with 60.49b(c) is not expected to be necessary because the facility has indicated a CEMS will be installed instead of using a predictive emissions system for NO_x. The reporting requirements of 60.49b(l) do not apply because the testing requirements of 60.45b(d) do not apply to this Boiler. 60.49b(n) does not apply because the SO_2 percent reduction requirements are not applicable per 60.42b(j), and this is because the permit requires only very low sulfur fuel oil to be used. 60.49b(p) and (q) do not apply since the NO_x requirements of 60.44b(j) and (k) do not apply. The following requirements of this section do not apply: 60.49b(l), 60.49b(n), 60.49(p), 60.49b(q), 60.49b(s), 60.49b(t), and 60.49b(u).

The following information applies to the SO_2 reporting requirements under 60.49b(j). Also refer to 60.42b(j) above regarding an applicability request sent to the EPA on April 6, 2004 concerning these requirements.

> The reporting requirements of 60.49b(k) do not apply when the when the SO_2 compliance and performance testing standards under 60.45b don't apply. This occurs, per 60.45b(j), when the facility combusts only very low sulfur oil (which is required by the permit) and fuel receipts are obtained in accordance with 60.49b(r). If the facility is not able to obtain fuel receipts in accordance with 60.49b(r), then the reporting requirements of 60.49b(k) apply.
>
> The reporting requirements of 60.49b(m) do not apply when the when the emission monitoring requirements under 60.47b don't apply. This occurs, per 60.47b(f), when the facility combusts only very low sulfur oil (which is required by the permit) and fuel receipts are obtained in accordance with 60.49b(r). If the facility is not able to obtain fuel receipts in accordance with 60.49b(r), then the reporting requirements of 60.49b(m) apply.

40 CFR 60.1 through 60.19, NSPS General Provisions. The NSPS General Provisions are given by 40 CFR Part 60 Subpart A. The General Provisions which apply to the boiler project have been added to the permit. The following requirements in this subpart do not apply: 60.18.

40 CFR 60 Subpart Kb .... New Source Performance Standards (NSPS) for Industrial, Commercial and Institutional Steam Generating Units

40 CFR 60.110b, Applicability. This NSPS subpart applies to the two new 30,000-gallon fuel oil storage tanks. Each tank is over 75 cubic meters (19,813 gallons) in volume, therefore, the applicability criteria in 40 CFR 60.110b(a) and (b) do not apply. However, 60.110b(c) does apply to both tanks, based on the following: *"Except as specified in paragraphs (a) and (b) of 60.116b, vessels either with a capacity greater than or equal to 151 M^3 [39,890 gallons] storing a liquid with a maximum true vapor pressure less than 3.5 kPa or with a capacity greater than or equal to 75 m^3 [19,813 gallons] but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa are exempt from the General Provisions (Part 60, subpart A) and from the provisions of this subpart."* It is noted that the vapor pressure of diesel fuel is approximately 0.067 kPa (0.5 mm Hg) and the vapor pressure of residual oil will be lower.

To comply with the requirements of 40 CFR Part 60 Subpart Kb, the facility will only need to comply with 60.116b(a) and (b). In particular, the facility will need to keep readily accessible records of the tank dimensions and the capacity for the life of each tank. This requirement was placed in Section 2 of the permit.

40 CFR 61 and 63 .... National Emission Standards for Hazardous Air Pollutants & MACT

There are no requirements under 40 CFR Parts 61 and 63 that apply to Larsen Farms.

5.4 Fee Review

Larsen Farms paid a $1,000 PTC application fee (IDAPA 58.01.01.224) when the permit application was delivered to DEQ on May 28, 2003. Since a Tier II operating permit will be issued, this amount was applied toward the Tier II processing fee.

A Tier II operating permit processing fee of $10,000 is required in accordance with IDAPA 58.01.01.407 because the increase in emissions from the Tier II permit is 100 tons or more per year as indicated in Table 5.5. This balance of this fee was received by DEQ from Larsen Farms on March 22, 2004.

Larsen Farms is a major facility as defined in IDAPA 58.01.01.008.10. Therefore, Tier I registration fees are applicable in accordance with IDAPA 58.01.01.387. As of March 22, 2004, the current balance due for Tier I fees is $0.00.

Table 5.5 Tier II Processing Fee Summary

Emissions Inventory	
Pollutant	**Permitted Emissions**
NO_X	162
SO_2	246
CO	60
PM_{10}	67.5
VOC	4.6
TAPS/HAPS	3.5
Total:	**639**
Tier II Fee	$10,000.00
Fees paid to date	$10,000.00
Fee Due	**$ 0.00**

6. PERMIT CONDITIONS

This section summarizes and explains the reasoning behind the permit conditions in the Tier II/PTC.

Permit Section 2

Standard facility-wide permit conditions which apply to this facility were added in Section 2 of the permit.

Permit Conditions 3.2, 3.3, 3.13, 3.14 and 4.3

Pound per day emission limits for the Boiler are established for PM_{10} and SO_2 for purposes of maintaining compliance with the NAAQS. These limits are established since the modeling results indicate the boiler, when fired with residual oil, is one of the main contributors to concentrations of PM_{10} and SO_2 to receptors near the facility. The 24-hour basis was used since modeling indicates compliance with the NAAQS 24-hour averaging time for PM_{10} and SO_2 will result in compliance with each of the other NAAQS averaging times for those pollutants. The PM_{10} daily emission limit is based on the emission rate for which compliance with the NAAQS was demonstrated in the application: PM_{10} = (8.29 lb/hr)(24 hr/day) = 199 lb/day. The SO_2 daily emission limit is based on the emission rate for which compliance with the NAAQS was demonstrated: SO_2 = (69.83 lb/hr)(24 hr/day) = 1,676 lb/day.

Annual emission limits are established for SO_2 on the order of 244 TPY for the Boiler and 3 TPY for other production processes; this effectively limits facility-wide emissions of SO_2 to no more than 247 TPY. This establishes federally enforceable permit conditions that will restrict total SO_2 emissions from the facility to less than the 250 TPY PSD threshold (see Permit Condition 4.3). As a result of these SO_2 limits, annual emissions of all other criteria pollutants are then inherently limited to levels well below the PSD threshold. Limits for certain TAPs were established in accordance with IDAPA 58.01.01.210.08.c.

Compliance with these emission limits is demonstrated by following the operating and monitoring requirements in the permit with regard to fuel sulfur content, fuel throughput, and the NSPS monitoring requirements for the Boiler. Note that the fuel throughput limits are based on the quantities used in the application to demonstrate compliance with applicable requirements. For fuel oil, the throughput limits are: (889 gal/hr)(24 hr/day) = 21,336 gal/day, and; (889 gal/hr)(7000 hr/yr) = 6.22 million gal/yr. Specific monitoring conditions for the production processes, other than the boiler, are not necessary for purposes of ensuring the 3 TPY SO_2 limit is exceeded since the emissions from these sources was estimated at the maximum capacity of each emission unit, the variability of the actual emissions is expected to be low; therefore, emissions from those units are not likely to exceed the 3 TPY limit.

Permit Condition 3.29

The permittee is required to conduct a performance test to demonstrate compliance with the PM standard for fuel burning equipment (IDAPA 58.01.01.676-677) when firing no. 6 fuel oil, as given in Section 2 of the permit.

Compliance is demonstrated by sending a copy of the performance test report to DEQ in accordance with Section 2 of the permit.

Permit Conditions in Section 3 for NSPS Subpart Db

Applicable NSPS requirements for the Boiler from 40 CFR Part 60 Subpart Db were added to the permit. Refer to the Regulatory Analysis Section of this document for details. Methods for determining compliance are included as part of the NSPS requirements where needed.

Permit Conditions 3.15 and 4.15

An operating requirement was established for modifying certain stacks, by increasing the height and/or the outlet orientation, prior to firing any fuel oil. This condition was added to the permit to ensure compliance with the PM_{10} and SO_2 NAAQS. These stack specifications represent the minimum values used in the modeling analyses to demonstrate compliance with the NAAQS when burning any type of fuel oil.

Compliance with this requirement is demonstrated by sending a notification to DEQ upon completion of the stack modifications.

Permit Conditions 3.13 and 3.18

As noted above for Condition 3.2, a fuel oil sulfur content limit of 0.5% by weight was added to the permit as an operating requirement. In addition, a permit limit was established for the nickel content by weight in the fuel oil for purposes of demonstrating compliance with IDAPA 58.01.01.203.03. The nickel concentration limit was established since the emission estimate provided in the application was based on specific manufacturer's data for nickel in fuel oil (1.76E-06 lb/1000 gal) which is considerably less than the AP-42 value typically relied upon for this analysis (8.45E-02 lb/1000 gal). The permit limit is based on the emission rate used in the model to demonstrate compliance with IDAPA 58.01.01.210 (i.e., 3.0E-04 lb/hr based on natural gas) and the maximum fuel throughput:

(3.0E-04 lb/hr)/(889 gal/hr) = 3.4E-07 lb/gal = 3.4E-04 pounds of nickel by weight per 1000 gallons of fuel. Using this limit, the maximum tons/yr allowed for Nickel was determined to be:

(3.4E-04 lb/hr)(7000 hr/yr)(ton/2000 lb) = 1.2E-03 tons/yr.

Compliance is demonstrated by fulfilling the permit requirement to perform sampling and analysis, or by obtaining and maintaining records of the sulfur content and the nickel content by weight for each load of fuel oil received.

Permit Condition 4.2, and 4.4 – 4.14

Pound per day PM_{10} emission limits for each dryer and the Flake Packaging Torit baghouse are established for purposes of maintaining compliance with the NAAQS. The limits are established since the modeling results indicate these emission units are primary contributors to concentrations of PM_{10} for receptors near the facility. For example, since each drum dryer contributes 3-4% of the NAAQS, all 12 dyers, as a group, contribute approximately 36-48% of the NAAQS. For flexibility purposes, a single emission limit was given for each group of similar dryers (e.g., the National dryer stacks and the Drum Dryer stacks); this grouping was acceptable since the model indicates all stacks within each group have similar impacts on the receptors. The 24-hour (i.e., lb/day) basis was used since modeling indicates compliance with the NAAQS 24-hour averaging time for PM_{10} will result in compliance with the annual NAAQS as well. The PM_{10} daily emission limits are derived below. Each one is based on the combustion and process emission rates, at the maximum rated capacities, for which compliance with the NAAQS was demonstrated in the application:

Dryer, Maxon, Fluidized bed type: PM_{10} = (0.03 + 0.73 lb/hr)(24 hr/day) = 18 lb/day.

Dryer, National, Stages A1, A2, B, C combined: PM_{10} = (4)(0.03 + 0.94 lb/hr)(24 hr/day) = 93 lb/day

Dryer, Drum type; Dryer Nos. 1-12 combined: PM_{10} = (12)(0.29 lb/hr)(24 hr/day) = 84 lb/day

Flake Packaging Torit Line: PM_{10} = (0.43 lb/hr)(24 hr/day) = 10 lb/day

Compliance with the emission limits is demonstrated through PM_{10} performance testing and using the emission factors obtained from the most recent test to show that the actual emission rate of each unit is less than or equal to the emission rate limit, based on the maximum rated throughput of the unit:
Actual Emissions = (Emission Factor from the Performance Test) x (Maximum Rated Throughput).
In addition, a facility production rate limit is established in the permit, including requirements to monitor and record the production rate. The facility production limit provides a demonstration that actual production levels will remain consistent with the application information that was used to demonstrate compliance with the NAAQS. For the baghouses compliance is also demonstrated through pressure drop monitoring and Operations and Maintenance (O&M) manual requirements. See below for details.

Permit Conditions 4.4 and 4.8

To demonstrate compliance with the applicable requirements for the facility, operating requirements were established to limit the combined daily production output, in pounds per day, from all twelve Flaker/Drum Dryers, the fluidized bed dryer, and the National Dryer. A daily basis is used for the production limit to correspond to the pound per day emission limits in Section 4 of the permit. The limits were based on the maximum production rates provided in Section 4, pages 28-33, of the application which were used by the permittee to demonstrate compliance. Establishing production limits for all of the dryer systems provides adequate monitoring for the entire facility since this effectively limits the production of the remaining processing units at the facility. The throughput limits are based on the following information:

Drum Dryers 1-12	16,000 lb/hr
Fluidized Bed Dryer	2,000 lb/hr
National Dryer	1,500 lb/hr
Total lb/hr output	19,500 lb/hr = 9.75 ton/hr

(19,500 lb/hr)(24 hr/day) = 468,000 lb/day = 234 tons/day

Compliance is demonstrated though a permit requirements to monitor and record the combined daily production output in pounds per day from the all 12 Flaker/Drum Dryers, the fluidized bed dryer, and the National Dryer.

Permit Conditions 4.5, 4.6, 4.9, and 4.10

For the material transfer system baghouses, emission estimates and the demonstration of compliance with applicable requirements are based on very high efficiency ratings. To demonstrate this efficiency is maintained over time, Larsen Farms is required to install, calibrate, maintain and operate pressure drop monitoring devices for each baghouse. In addition, an O&M manual must be developed, in accordance with the manufacturer's specifications, and followed for each of the four baghouses.

Compliance is demonstrated by meeting the following minimum requirements that the permittee must addressed in the O&M manual:

- Procedures for maintaining the pressure drops across each baghouse within manufacturer's and O&M manual specifications and monitoring/recording pressure drops on daily basis.
- The O&M manual shall address the operation, maintenance, and repair of the air pollution control equipment and shall, at a minimum, include:
- A general description, normal operating conditions and procedures, methods of preventing malfunctions, appropriate corrective actions to be taken, and provisions for weekly inspections.
- The O&M manual shall be maintained onsite at all times and shall be made available to DEQ representatives upon request.

Permit Condition 4.7

A requirement to combust only natural gas or propane in each dryer and the propane heaters was added to demonstrate that the 3 TPY SO_2 emissions limit is met for all production processes, excluding the boiler. A specific compliance demonstration is not necessary for this permit condition; compliance may be assessed at the time of each DEQ inspection and within the forthcoming Title V annual compliance certifications.

Permit Condition 4.11 – 4.14

To demonstrate compliance with the PM_{10} emission limits in Permit Condition 4.2 and the PM_{10} NAAQS for the facility, and because of uncertainty associated with the emission estimates for these emission units, performance tests are required for each of the following: one stage of the National Dryer; the Fluidized Bed Dryer; one of the 12 Flaker/Drum Dryers and; one of the four Flake Packaging Line baghouses.

7. PUBLIC COMMENT

A 30-day public comment period for the proposed permit was held from March 11, 2004 through April 12, 2004 in accordance with IDAPA 58.01.01.404.01.c. A notice was published in the Post Register in Idaho Falls on March 11, and copies of the proposed action were located at the Clark County Public Library, and the DEQ offices in Idaho Falls and in Boise in accordance with this rule. Comments were received only from Larsen Farms. The comments were reviewed, the permit and Statement of Basis were revised as necessary, and a Response to Comments document is provided in Appendix D.

8. RECOMMENDATION

Based on review of application materials and all applicable state and federal rules and regulations, staff recommend that Larsen Farms be issued final Tier II/PTC No. T2-030514 for the potato dehydration facility located near Dubois. Public comment requirements have been met and the project does not involve PSD requirements.

KH/sd P-030514

G:\Air Quality\Stationary Source\SS LTD\T2\Blaine Larsen Farms\Final\T2-030514 Final Sb.Doc

Appendix A

Blaine Larsen Farms, Dubois

T2-030514

1. Technical Analysis by D. Pitman (Emissions Inventory)

2. 5/17/04 Letter from Larsen Farms, PSD Applicability Analysis

3. Process Weight Rate Calculations

4. Applicability Determination Index Document; Control No. NN06

Technical Analysis

January 27, 2004

Larsen Farms, Hamer

P-030514

Prepared by:

Dan Pitman, Senior Engineer
Division of Technical Services

Acronyms, Units, and Chemical Nomenclatures

acfm	actual cubic feet per minute
Btu	British thermal unit
CO	carbon monoxide
DEQ	Department of Environmental Quality
EPA	Environmental Protection Agency
fps	feet per second
IDAPA	A numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
lb/hr	pound per hour
MMBtu	Million British thermal units
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
PM	Particulate Matter
PM_{10}	Particulate Matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
scf	standard cubic feet
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/yr	Tons per year

PURPOSE

The purpose for this memorandum is to review emissions estimates from Blaine Larsen Farms Dehydration Division (Larsen Farms) for a potato dehydration plant.

PROJECT DESCRIPTION

Larsen Farms is proposing to modify their existing 144-million British thermal unit (MMBtu) boiler so that it can combust distillate fuel oil, residual fuel oil and natural gas. Currently the boiler operates on propane only. There are eight other existing combustion sources which burn natural gas and propane.

TECHNICAL ANALYSIS

Process Description

The application included emissions estimates for nine combustion sources. The facility proposes to combust propane, natural gas, distillate fuel oil, and residual fuel oil. The application also included emissions estimates for 21 point sources of particulate matter emissions from processing raw potatoes to dehydrated potatoes.

Equipment Listing

Fuel Burning Equipment

Boiler - 144 MMBtu, fired with: natural gas, propane, distillate fuel oil, and residual fuel oil
Fluidized Bed Dryer - 4.5 MMBtu, fired with: natural gas and propane
4 National Dryers - 3.6 MMBtu, fired with: natural gas and propane
3 Heaters - 1.2 MMBtu, fired with: natural gas and propane

Process Equipment

12 - Drum dryers
4 - National dryers
Fluidized bed dryer
Flake packaging bulk line
Flake packaging line
Flake packaging torit line
Flake Packaging drum negative air baghouse

Emission Estimates

Process Equipment

The applicant estimated particulate matter emissions from all process equipment based on "past experience with similar facilities." No discussion was provided on how particulate matter is generated or how or why particulate matter emissions may vary.

Table 1 gives the applicant's emissions estimates from process equipment at the facility. The emissions estimates in Table 1 are for process emissions and do not include combustion byproducts.

Table 1. Process Equipment Particulate Emissions

Process Equipment	PM[a]		PM_{10}[b]		Production Rate
	lb/hr[c]	T/yr[d]	lb/hr[c]	T/yr[d]	lb/hr[c]
Drum Dryers (1-12)[e]	0.67	2.92	0.29	1.28	1,333
National Dryers (A1, A2, B, C)[f]	0.94	4.11	0.94	4.11	376
Fluidized Bed Dryer	1.65	7.23	0.73	3.18	2,000
Flake Packaging Bulk Line	0.129	0.57	0.065	0.283	12,000
Flake Packaging Line	0.065	0.28	0.032	0.141	6,000
Flake Packaging Torit Line	0.86	3.77	0.43	1.883	8,000
Flake Packaging Drum Negative Air Baghouse	0.194	0.85	0.097	0.424	18,000

a) Particulate matter
b) Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
c) Pounds per hour
d) Tons per year
e) There are 12 drum dryers, emissions given in the table are for a single drum dryer
f) There are 4 National dryers, emissions given in the table are for a single dryer

Combustion Sources

The applicant estimated emissions from the 144-MMBtu boiler while combusting natural gas, propane, distillate fuel oil, and residual fuel oil. Emissions estimates made by the applicant and confirmatory emissions estimates made by the Department of Environmental Quality (DEQ) were made using AP-42[1] Chapter 1.3, 1.4, and 1.5 emissions factors. Particulate matter (PM) emissions were assumed by the applicant to be equal to particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}) emissions for all fuels. Sulfur dioxide (SO_2) emissions for natural gas combustion in the boiler are based on AP-42 emissions factors that assume sulfur concentration in the natural gas is 0.2 grains per hundred standard cubic feet. Sulfur dioxide emissions from liquefied petroleum gas combustion in the boiler are based on sulfur concentrations of 15 grains per hundred standard cubic feet of gas which is stated by the applicant to be based on the *Gas Processors Association Engineering Data Book*. Sulfur dioxide emissions from distillate and residual fuel oil combustion in the boiler are based on a sulfur concentration in the fuel of 0.5 percent by weight.

The applicant provided emissions estimates from natural gas and liquefied petroleum gas combustion in the National dryers, fluidized bed dryer, and heaters. Emissions estimates are based on AP-42 chapter 1.4 and 1.5 emissions factors. Sulfur dioxide emissions estimates are based on a natural gas sulfur concentration of 0.2 grains per hundred standard cubic feet and a liquefied petroleum gas sulfur concentration of 15 grains per hundred standard cubic feet.

Table 2 provides a summary of criteria pollutant emissions estimates for all combustion sources. Worst case lead emissions are estimated to be 0.00134 pounds per hour from oil combustion in the boiler. Emissions estimates provided in Table 2 are based on the use of the fuel that gives the greatest emissions rates. All annual emissions estimates for gaseous fuel combustion are based 8,760 hours per year of operations. Annual emissions estimates for the boiler while combusting residual and distillate fuel oil are based on 7,000 hours per year of operation. The applicant's emissions estimates and DEQ's confirmatory emissions estimates were identical for all practical purposes except for nitrogen oxides emissions from the heaters. Table 2 gives the results of emissions estimates; values calculated by the applicant which differ from DEQ's confirmatory

---

[1] *Compilation of Air Pollutant Emission Factors* (AP-42), Fifth Edition, Volume I: *Stationary Point and Area Sources*, U. S. Environmental Protection Agency, Washington, DC.

emissions estimates are in parentheses. DEQ's confirmatory emission estimates calculations for the combustion sources may be seen in Attachment A.

Table 2. Summary of Emissions Estimates from Combustion Sources

Process Equipment	PM[a]/PM_{10}[b]		SO_2[c]		NO_x[d]		CO[e]		VOCs[f]	
	lb/hr[g]	T/yr[h]	lb/hr[g]	T/yr[h]	lb/hr[g]	T/yr[h]	lb/hr[g]	T/yr[h]	lb/hr[g]	T/yr[h]
Boiler	8.3	29.0	69.8	244	41.8	146	11.86	51.94	1.14	3.98
Fluidized Bed Dryer	0.03	0.15	0.07	0.32	0.69 (0.67[i])	3.02 (2.94[i])	0.37 (0.38[i])	1.62 (1.66[i])	0.025 (0.02[i])	0.11
National Dryer[j]	0.03	0.12	0.06	0.26	0.55	2.4	0.3	1.3 (1.32[i])	0.02	0.09
Heater (3 heaters)	0.03	0.12	0.06	0.26	0.55 (0.68[i])	2.42 (3.00[i])	0.3	1.3 (1.32[i])	0.02	0.09

a) Particulate matter
b) Particulate Matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
c) Sulfur dioxide
d) Nitrogen oxides
e) Carbon monoxide
f) Volatile organic compounds
g) Pounds per hour
h) Tons per year
i) Values in parentheses are calculated by the applicant and are different than DEQ calculated values
j) Emission estimates for the National Dryer are for a single emissions unit, all four National Dryers emit at the same rate

Process Emissions and Combustion Emissions

Attachment B contains a summary table of all emissions estimates. The summary table includes process and combustion emissions estimates. This summary table is similar to summary tables the applicant provided.

Toxic Air Pollutant Emissions

Toxic air pollutant emissions estimates were made for natural gas combustion, distillate and residual fuel oil combustion. Toxic air pollutant emission factors were not available for liquefied petroleum gas combustion. DEQ's confirmatory toxic air pollutant emissions estimates may be seen in Attachment A and are based on AP-42 emissions factors for all pollutants.

DEQ assumed that all chromium emissions from natural gas combustion are hexavalent chromium. Values given in parentheses in the table are values the applicant calculated that are different than those calculated by DEQ. All emissions estimates made by the applicant are based on AP-42 emission factors except for nickel emissions from fuel oil combustion in the boiler, which are stated to be based on the nickel concentration in the fuel oil. The applicant did not state what that concentration was but did use an emissions factor of 1.67E-6 pounds of nickel per thousand gallons of fuel oil. All of DEQ's confirmatory emission estimates, including emissions estimates for nickel, are made using AP-42 emission factors.

Table 3. Worst Case Toxic Air Pollutant Emissions Summary

Source	Boiler Emissions (lb/hr)[a]	Four National Dryers[b] (lb/hr)[a]	Fluidized Bed Dryer (lb/hr)[a]	Three Heaters[c] (lb/hr)[a]
Formaldehyde	2.93E-2	1.06E-3 (1.08E-3[d])	3.31E-4 (3.4E-4[d])	2.65E-4 (2.7E-4[d])
Arsenic	1.17E-3	2.82E-6 (2.88E-6[d])	8.82E-7 (9.0E-7[d])	7.06E-7 (7.2E-7[d])
Cadmium	3.54E-4 (4.0E-4[d])	1.55E-5 (1.6E-5)	4.85E-6 (5.0E-6[d])	3.88E-6 (4.0E-6[d])
Chromium VI	2.20E-4	1.98E-5 (0.0[d])	6.18E-6 (0.0[d])	4.94E-6 (0.0[d])
Cobalt	5.35E-3	1.19E-6	3.71E-7 (3.8E-7[d])	2.96E-7 (3.0e-7[d])
Nickel	7.51E-2 (3.0E-4[d])	2.96E-5 (3.04E-5[d])	9.26E-6 (9.5E-6[d])	7.41E-6 (7.6E-6[d])
Phosphorus	8.41E-3	No Data	No Data	No Data

a) Pounds per hour
b) Emissions given in the table are for the sum of 4 National Dryers
c) Emissions given in the table are for the sum of 3 heaters
d) Emission estimates provided by the applicant which are different than DEQ estimates

Hazardous Air Pollutants

Potential hazardous air pollutant emissions from the facility are significantly less than 10 tons per year for any one hazardous air pollutant and less than 25 tons per year for all hazardous air pollutants in aggregate.

Stack Parameter Basis

DEQ performed a combustion evaluation on the boiler while combusting No. 6 fuel oil to determine the theoretical combustion gas flowrates to compare to the flowrates the applicant supplied for the boiler. The combustion evaluation calculations may be seen in Attachment D.

Table 4 compares the combustion gas flowrates and velocity supplied in the application to the combustion gas flowrate and velocity determined by DEQ's combustion evaluation. The flowrates and velocities are identical for all practical purposes.

Table 4. Boiler Gas Flowrate and Velocity

Source of Data	Gas Flowrate (acfm)[a]	Gas Velocity (fps)[b]
Applicant Supplied	59,000	28.5
DEQ Calculated	59,584	28.6

a) Actual cubic feet per minute
b) Feet per second

Particulate Matter Grain Loading

The particulate matter grain loading emissions concentration was calculated to be 0.03 grains per dry standard cubic foot corrected to 3% oxygen for combustion of residual fuel oil in the boiler. The particulate matter grain loading concentration emissions estimate may be seen in Attachment E. Particulate matter emissions are expected to increase with increasing concentrations of ash and sulfur in the fuel oil.

Source Testing

The applicant did not submit source testing data in the application materials.

Operating Parameters

The applicant estimated particulate matter emissions from all process equipment based on "past experience with similar facilities." It is expected that particulate matter emissions rates would vary proportionately with production rates.

Emissions estimates from all combustion sources at the facility were estimated using AP-42 emission factors. Emissions of carbon monoxide are dependent on the efficiency of combustion in all of the fuel burning equipment. Particulate matter emissions from the boiler while burning residual fuel oil are expected to fluctuate proportionately with the ash and sulfur concentrations in the fuel oil. Emissions estimates for particulate matter emissions from the boiler while combusting residual fuel oil are based on a sulfur concentration of 0.5 percent by weight.

Emission estimates from the boiler while combusting fuel oils is based on 7,000 hours per year of operation and 8,760 hours per year while combusting gaseous fuels. All other process and fuel burning equipment emissions estimates are based on 8,760 hours per year of operation.

DP/sl P-030514

Attachment A

Emissions Estimate Calculations

Larsen Farms - Boiler (Distillate Fuel Oil)

Distillate Fuel Oil Combustion > 100 MMBtu/hr

Input Capcity = 1.44E+08 Btu/hr

Fuel usage rate = 889.000 gal/hr
Sulfur Content = 0.5 % by weight
Annual hours of operation= 7000

Pollutant	[illegible]	[illegible]	[illegible]
SO_2	157*S[5]	69.767	244.2528
SO_3	5.7*S[5]	2.534	8.867775
NO_x	24	21.336	74.676
CO	5	4.445	15.5575
PM Total	3.3	2.934	10.26795
VOC[2]	0.252	0.224	7.84E-01
Benzene	2.14E-04	1.90E-04	6.66E-04
Ethylbenzene	6.36E-05	5.65E-05	1.98E-04
Formaldehyde	3.30E-02	2.93E-02	1.03E-01
Naphthalene	1.13E-03	1.00E-03	3.52E-03
1,1,1-Trichloroethane	2.36E-04	2.10E-04	7.34E-04
Toluene	6.20E-03	5.51E-03	1.93E-02
o-Xylene	1.09E-04	9.69E-05	3.39E-04
Acenaphthene	2.11E-05	1.88E-05	6.57E-05
Acenaphthylene	2.53E-07	2.25E-07	7.87E-07
Anthracene	1.22E-06	1.08E-06	3.80E-06
Benz(a)anthracene[3]	4.01E-06	3.56E-06	1.25E-05
Benzo(b,k)fluoranthene	1.48E-06	1.32E-06	4.61E-06
Benzo(g,h,i)perylene	2.26E-06	2.01E-06	7.03E-06
Chrysene[3]	2.38E-06	2.12E-06	7.41E-06
Dibenzo(a,h)anthracene[3]	1.67E-06	1.48E-06	5.20E-06
Fluoranthene	4.84E-06	4.30E-06	1.51E-05
Fluorene	4.47E-06	3.97E-06	1.39E-05
Indo (1,2,3-cd)pyrene[3]	2.14E-06	1.90E-06	6.66E-06
PAH[4]	1.02E-05	9.07E-06	3.17E-05
Phenanthrene	1.05E-05	9.33E-06	3.27E-05
Pyrene	4.25E-06	3.78E-06	1.32E-05
Antimony	5.25E-03	4.67E-03	1.63E-02
Arsenic	1.32E-03	1.17E-03	4.11E-03
Barium	2.57E-03	2.28E-03	8.00E-03
Beryllium	2.78E-05	2.47E-05	8.65E-05
Cadmium	3.98E-04	3.54E-04	1.24E-03
Chloride	3.47E-01	3.08E-01	1.08E+00
Chromium	8.45E-04	7.51E-04	2.63E-03
Chromium VI	2.48E-04	2.20E-04	7.72E-04
Cobalt	6.02E-03	5.35E-03	1.87E-02
Copper	1.76E-03	1.56E-03	5.48E-03
Fluoride	3.73E-02	3.32E-02	1.16E-01
Lead	1.51E-03	1.34E-03	4.70E-03
Manganese	3.00E-03	2.67E-03	9.33E-03
Mercury	1.13E-04	1.00E-04	3.52E-04
Molybdenum	7.87E-04	7.00E-04	2.45E-03
Nickel	8.45E-02	7.51E-02	2.63E-01
Phosphorous	9.46E-03	8.41E-03	2.94E-02
Selenium	6.83E-04	6.07E-04	2.13E-03
Vanadium	3.18E-02	2.83E-02	9.89E-02
Zinc	2.91E-02	2.59E-02	9.05E-02

1) AP-42 Emission Factors for Distillate fuel oil combustion greater than 100E6 Btu/hr, Section 1.3
2) Assume total organic compounds is equivalent VOC
3) Compounds which make up PAH
4) Polyaromatic Hydrocarbons
5) Sulfur content in %

Larsen Farms - Boiler (Residual Fuel Oil)

#6 Fuel Oil Combustion > 100 MMBtu/hr

Input Capcity = 1.44E+08 Btu/hr

Fuel usage rate = 889 gal/hr
Sulfur Content = 0.5 % by weight
Annual hours of operation= 7000

[illegible]	[illegible]	[illegible]	[illegible]
SO_2	157*S[e]	69.787	244.25275
SO_3	5.7*S[e]	2.534	8.867775
NO_x	47	41.783	146.2405
CO	5	4.445	15.5575
PM Total	9.19(S[e])+ 3.22+1.5	8.281	28.983623
VOC[b]	1.28	1.138	3.98272
Benzene	2.14E-04	1.90E-04	6.66E-04
Ethylbenzene	6.36E-05	5.65E-05	1.98E-04
Formaldehyde	3.30E-02	2.93E-02	1.03E-01
Naphthalene	1.13E-03	1.00E-03	3.52E-03
1,1,1-Trichloroethane	2.36E-04	2.10E-04	7.34E-04
Toluene	6.20E-03	5.51E-03	1.93E-02
o-Xylene	1.09E-04	9.69E-05	3.39E-04
Acenaphthene	2.11E-05	1.88E-05	6.57E-05
Acenaphthylene	2.53E-07	2.25E-07	7.87E-07
Anthracene	1.22E-06	1.08E-06	3.80E-06
Benz(a)anthracene[c]	4.01E-06	3.56E-06	1.25E-05
Benzo(b,k)fluoranthene	1.48E-06	1.32E-06	4.61E-06
Benzo(g,h,i)perylene	2.26E-06	2.01E-06	7.03E-06
Chrysene[c]	2.38E-06	2.12E-06	7.41E-06
Dibenzo(a,h)anthracene[c]	1.67E-06	1.48E-06	5.20E-06
Fluoranthene	4.84E-06	4.30E-06	1.51E-05
Fluorene	4.47E-06	3.97E-06	1.39E-05
Indo (1,2,3-cd)pyrene[c]	2.14E-06	1.90E-06	6.66E-06
PAH[d]	1.02E-05	9.07E-06	3.17E-05
Phenanthrene	1.05E-05	9.33E-06	3.27E-05
Pyrene	4.25E-06	3.78E-06	1.32E-05
Antimony	5.25E-03	4.67E-03	1.63E-02
Arsenic	1.32E-03	1.17E-03	4.11E-03
Barium	2.57E-03	2.28E-03	8.00E-03
Beryllium	2.78E-05	2.47E-05	8.65E-05
Cadmium	3.98E-04	3.54E-04	1.24E-03
Chloride	3.47E-01	3.08E-01	1.08E+00
Chromium	8.45E-04	7.51E-04	2.63E-03
Chromium VI	2.48E-04	2.20E-04	7.72E-04
Cobalt	6.02E-03	5.35E-03	1.87E-02
Copper	1.76E-03	1.56E-03	5.48E-03
Fluoride	3.73E-02	3.32E-02	1.16E-01
Lead	1.51E-03	1.34E-03	4.70E-03
Manganese	3.00E-03	2.67E-03	9.33E-03
Mercury	1.13E-04	1.00E-04	3.52E-04
Molybdenum	7.87E-04	7.00E-04	2.45E-03
Nickel	8.45E-02	7.51E-02	2.63E-01
Phosphorous	9.46E-03	8.41E-03	2.94E-02
Selenium	6.83E-04	6.07E-04	2.13E-03
Vanadium	3.18E-02	2.83E-02	9.89E-02
Zinc	2.91E-02	2.59E-02	9.05E-02

a) AP-42 Emission Factors for #6 fuel oil combustion greater than 100E6 Btu/hr, Section 1.3
b) Assume total organic compounds is equivalent VOC
c) Compounds which make up PAH
d) Polyaromatic Hydrocarbons
e) Sulfur content in %

Larsen Farms - Boiler (NG)
Natural Gas Combustion in Boiler

Source	Larsen Farms	
Emission Unit -	Boiler	
Input Rating (Btu/hr) -	1.44E+08	(per applicant's submittal)
Gas Heating Value (Btu/ft^3)	1.02E+03	(per applicant's submittal)
Cubic Feet Cumbusted per hour -	141176.47	
Hours of Operation Per Year -	8760	

[illegible] Pollutant	Emission Factor* (lb/10E6 scf)	Emission (lb/hr)	Emission (tpy)
PM-10 (total)	7.6	1.07E+00	4.70
SO_2	0.6	8.47E-02	0.37
VOC	5.5	7.76E-01	3.40
NOx**	140	19.76	86.57
CO	84	11.86	51.94

* AP-42, Table 1.4-1, greater than 100 MMBtu/hr
** Low NOx Burner

[illegible] Pollutant	Emission Factor* (lb/10E6 scf)	Emission (lb/hr)	Emission (tpy)
2-Methylnaphthalene	2.40E-05	3.39E-06	1.48E-05
3-Methylchloranthrene	1.80E-06	2.54E-07	1.11E-06
7,12-Dimethylbenz(a)anthracne	1.60E-05	2.26E-06	9.89E-06
Acenaphthene	1.80E-06	2.54E-07	1.11E-06
Acenaphylene	1.80E-06	2.54E-07	1.11E-06
Anthracene	2.40E-06	3.39E-07	1.48E-06
Benz(a)anthracene[1]	1.80E-06	2.54E-07	1.11E-06
Benzene	2.10E-03	2.96E-04	1.30E-03
Benzo(a)pyrene[1]	1.20E-06	1.69E-07	7.42E-07
Benzo(b)fluoranthene[1]	1.80E-06	2.54E-07	1.11E-06
Benzo(g,h,l)perylene	1.20E-06	1.69E-07	7.42E-07
Benzo(k)fluoranthene[1]	1.80E-06	2.54E-07	1.11E-06
Butane	2.10E+00	2.96E-01	1.30E+00
Chrysene[1]	1.80E-06	2.54E-07	1.11E-06
Dibenzo(a,h)anthracene[1]	1.20E-06	1.69E-07	7.42E-07
Dichlorobenzene	1.20E-03	1.69E-04	7.42E-04
Ethane	3.10E+00	4.38E-01	1.92E+00
Fluoranthene	3.00E-06	4.24E-07	1.86E-06
Fluorene	2.80E-06	3.95E-07	1.73E-06
Formaldehyde	7.50E-02	1.06E-02	4.64E-02
Hexane	1.80E+00	2.54E-01	1.11E+00
Ideno(1,2,3-cd)pyrene[1]	1.80E-06	2.54E-07	1.11E-06
Naphthalene	6.10E-04	8.61E-05	3.77E-04
PAH[2]	1.14E-05	1.61E-06	7.05E-06
Pentane	2.60E+00	3.67E-01	1.61E+00
Phenanathrene	1.70E-05	2.40E-06	1.05E-05
Propane	1.60E+00	2.26E-01	9.89E-01
Pyrene	5.00E-06	7.06E-07	3.09E-06
Toluene	3.40E-03	4.80E-04	2.10E-03
Arsenic	2.00E-04	2.82E-05	1.24E-04
Barium	4.40E-03	6.21E-04	2.72E-03
Beryllium	1.20E-05	1.69E-06	7.42E-06
Cadmium	1.10E-03	1.55E-04	6.80E-04
Chromium	1.40E-03	1.98E-04	8.66E-04
Cobalt	8.40E-05	1.19E-05	5.19E-05
Copper	8.50E-04	1.20E-04	5.26E-04
Manganese	3.80E-04	5.36E-05	2.35E-04
Mercury	2.60E-04	3.67E-05	1.61E-04
Molybdenum	1.10E-03	1.55E-04	6.80E-04
Nickel	2.10E-03	2.96E-04	1.30E-03
Selenium	2.40E-05	3.39E-06	1.48E-05
Vanadium	2.30E-03	3.25E-04	1.42E-03
Zinc	2.90E-02	4.09E-03	1.79E-02

* AP-42 Chapter 1.4
1) Compounds which make up polyaromatic hydrocarbons
2) Polyaromatic hydrocarbons

Heat Input of Source = 1.44E+08 Btu/hr

Sulfur Content = 15 grains/100 ft^3 (per applicant's submittal)

Annual operations = 8760 hours

Pollutant	Emission Factor (lb/1000 gal)	Emission Rate (lb/hr)	Emission Rate (t/yr)
Particulate Matter	0.6	0.944	4.136
Sulfur Dioxide	0.1S[2]	2.361	10.340
Nitrogen Oxides	19	29.902	130.969
Carbon Monoxide	3.2	5.036	22.058
VOC[3]	0.5	0.787	3.447

1) AP-42, Section 1.5, Table 1.5-1 (large source: 10 - 100 MMBtu/hr)

2) Sulfur Content of fuel in grains per 100 ft^3

3) Volatile organic compounds (assumed to be equal to total organic compounds)

Larsen Farms

Fluidized bed dryer

Natural Gas Combustion	4.50E+06	Btu/hr	(per applicant's submittal)
Heat Content of Natural Gas	1020	Btu/ft^3	(per applicant's submittal)

Emission Factors are from AP-42 Section 1.4, 7/98 (< 100E6 Btu/hr)

Annual hours of operation 8760

Pollutant	Emission Factor (lb/E6 scf)	Emission Rate (lb/hr)	Emission Rate (T/yr)
NOx	100	4.41E-01	1.93E+00
CO	84	3.71E-01	1.62E+00
PM	7.6	3.35E-02	1.47E-01
SO2	0.6	2.65E-03	1.16E-02
VOC	5.5	2.43E-02	1.06E-01
2-Methylnaphthalene	2.45E-05	1.08E-07	4.73E-07
3-Methylchloranthrene	1.80E-06	7.94E-09	3.48E-08
7,12-Dimethylbenz(a)anthracene	1.60E-05	7.06E-08	3.09E-07
Acenaphthene	1.80E-06	7.94E-09	3.48E-08
Acenaphthylene	1.80E-06	7.94E-09	3.48E-08
Anthracene	2.40E-06	1.06E-08	4.64E-08
Benz(a)anthracene (1)	1.80E-06	7.94E-09	3.48E-08
Benzene	2.10E-03	9.26E-06	4.06E-05
Benz(a)pyrene (1)	1.20E-06	5.29E-09	2.32E-08
Benzo(b)fluoranthene (1)	1.80E-06	7.94E-09	3.48E-08
Benzo(g,h,i)perylene	1.20E-06	5.29E-09	2.32E-08
Benzo(k)fluoranthene (1)	1.80E-06	7.94E-09	3.48E-08
Butane	2.10E+00	9.26E-03	4.06E-02
Chrysene (1)	1.80E-06	7.94E-09	3.48E-08
Dibenzo(a,h)anthracene (1)	1.20E-06	5.29E-09	2.32E-08
Dichlorobenzene	1.20E-03	5.29E-06	2.32E-05
Ethane	3.10E+00	1.37E-02	5.99E-02
Fluoranthene	3.00E-06	1.32E-08	5.80E-08
Fluorene	2.80E-06	1.24E-08	5.41E-08
Formaldehyde	7.50E-02	3.31E-04	1.45E-03
Hexane	1.80E+00	7.94E-03	3.48E-02
Indeno(1,2,3-cd)pyrene (1)	1.80E-06	7.94E-09	3.48E-08
Naphthalene	6.10E-04	2.69E-06	1.18E-05
PAH (2)	1.14E-05	5.03E-08	2.20E-07
Pentane	2.60E+00	1.15E-02	5.02E-02
Phenanathrene	1.70E-05	7.50E-08	3.29E-07
Propane	1.60E+00	7.06E-03	3.09E-02
Pyrene	5.00E-06	2.21E-08	9.66E-08
Toluene	3.40E-03	1.50E-05	6.57E-05
Arsenic	2.00E-04	8.82E-07	3.86E-06
Barium	4.40E-03	1.94E-05	8.50E-05
Beryllium	1.20E-05	5.29E-08	2.32E-07
Cadmium	1.10E-03	4.85E-06	2.13E-05
Chromium	1.40E-03	6.18E-06	2.71E-05
Cobalt	8.40E-05	3.71E-07	1.62E-06
Copper	8.50E-04	3.75E-06	1.64E-05
Manganese	3.80E-04	1.68E-06	7.34E-06
Mercury	2.60E-04	1.15E-06	5.02E-06
Molybdenum	1.10E-03	4.85E-06	2.13E-05
Nickel	2.10E-03	9.26E-06	4.06E-05
Selenium	2.40E-05	1.06E-07	4.64E-07
Vanadium	2.30E-03	1.01E-05	4.44E-05
Zinc	2.90E-02	1.28E-04	5.60E-04

(1) Compounds which make up PAH

(2) Sum of emission factors which make up PAH

Larsen Farms

Fluidized bed dryer - LPG

Liquified Petroleum Gas Combustion

Small Combustion Sources (0.3-10MMBtu/hr)

Heat Content of LPG	=	9.15E+07	Btu/1000 gal, AP-42, Section 1.5.3.1
Heat Input of Source	=	4.50E+06	Btu/hr
Sulfur Content	=	15	grains/100 ft^3 (per applicant's submittal)
Annual operations	=	8760	hours

Pollutant	Emission Factor (lb/10^3 gal)	Emission Rate (lb/hr)	Emission Rate (T/yr)
Particulate Matter	0.4	0.020	0.086
Sulfur Dioxide	0.1S[b]	0.074	0.323
Nitrogen Oxides	14	0.689	3.016
Carbon Monoxide	1.9	0.093	0.409
VOC[c]	0.5	0.025	0.108

a) AP-42, Section 1.5, Table 1.5-1

b) Sulfur Content of fuel in grains per 100 ft^3

c) Volatile organic compounds (assumed to be equal to total organic compounds)

Larsen Farms

Pollutant	Emission Factor [illegible]	[illegible]	[illegible]	[illegible]
NOx	100	3.53E-01	1.41E+00	6.18E+00
CO	84	2.96E-01	1.19E+00	5.19E+00
PM	7.6	2.68E-02	1.07E-01	4.70E-01
SO2	0.6	2.12E-03	8.47E-03	3.71E-02
VOC	5.5	1.94E-02	7.76E-02	3.40E-01
2-Methylnaphthalene	2.45E-05	8.65E-08	3.46E-07	1.51E-06
3-Methylchloranthrene	1.80E-06	6.35E-09	2.54E-08	1.11E-07
7,12-Dimethylbenz(a)anthracene	1.60E-05	5.65E-08	2.26E-07	9.89E-07
Acenaphthene	1.80E-06	6.35E-09	2.54E-08	1.11E-07
Acenaphthylene	1.80E-06	6.35E-09	2.54E-08	1.11E-07
Anthracene	2.40E-06	8.47E-09	3.39E-08	1.48E-07
Benz(a)anthracene (1)	1.80E-06	6.35E-09	2.54E-08	1.11E-07
Benzene	2.10E-03	7.41E-06	2.96E-05	1.30E-04
Benz(a)pyrene (1)	1.20E-06	4.24E-09	1.69E-08	7.42E-08
Benzo(b)fluoranthene (1)	1.80E-06	6.35E-09	2.54E-08	1.11E-07
Benzo(g,h,l)perylene	1.20E-06	4.24E-09	1.69E-08	7.42E-08
Benzo(k)fluoranthene (1)	1.80E-06	6.35E-09	2.54E-08	1.11E-07
Butane	2.10E+00	7.41E-03	2.96E-02	1.30E-01
Chrysene (1)	1.80E-06	6.35E-09	2.54E-08	1.11E-07
Dibenzo(a,h)anthracene (1)	1.20E-06	4.24E-09	1.69E-08	7.42E-08
Dichlorobenzene	1.20E-03	4.24E-06	1.69E-05	7.42E-05
Ethane	3.10E+00	1.09E-02	4.38E-02	1.92E-01
Fluoranthene	3.00E-06	1.06E-08	4.24E-08	1.86E-07
Fluorene	2.80E-06	9.88E-09	3.95E-08	1.73E-07
Formaldehyde	7.50E-02	2.65E-04	1.06E-03	4.64E-03
Hexane	1.80E+00	6.35E-03	2.54E-02	1.11E-01
Indeno(1,2,3-cd)pyrene (1)	1.80E-06	6.35E-09	2.54E-08	1.11E-07
Naphthalene	6.10E-04	2.15E-06	8.61E-06	3.77E-05
PAH (2)	1.14E-05	4.02E-08	1.61E-07	7.05E-07
Pentane	2.60E+00	9.18E-03	3.67E-02	1.61E-01
Phenanathrene	1.70E-05	6.00E-08	2.40E-07	1.05E-06
Propane	1.60E+00	5.65E-03	2.26E-02	9.89E-02
Pyrene	5.00E-06	1.76E-08	7.06E-08	3.09E-07
Toluene	3.40E-03	1.20E-05	4.80E-05	2.10E-04
Arsenic	2.00E-04	7.06E-07	2.82E-06	1.24E-05
Barium	4.40E-03	1.55E-05	6.21E-05	2.72E-04
Beryllium	1.20E-05	4.24E-08	1.69E-07	7.42E-07
Cadmium	1.10E-03	3.88E-06	1.55E-05	6.80E-05
Chromium	1.40E-03	4.94E-06	1.98E-05	8.66E-05
Cobalt	8.40E-05	2.96E-07	1.19E-06	5.19E-06
Copper	8.50E-04	3.00E-06	1.20E-05	5.26E-05
Manganese	3.80E-04	1.34E-06	5.36E-06	2.35E-05
Mercury	2.60E-04	9.18E-07	3.67E-06	1.61E-05
Molybdenum	1.10E-03	3.88E-06	1.55E-05	6.80E-05
Nickel	2.10E-03	7.41E-06	2.96E-05	1.30E-04
Selenium	2.40E-05	8.47E-08	3.39E-07	1.48E-06
Vanadium	2.30E-03	8.12E-06	3.25E-05	1.42E-04
Zinc	2.90E-02	1.02E-04	4.09E-04	1.79E-03

(1) Compounds which make up PAH
(2) Sum of emission factors which make up PAH

Larsen Farms

National dryer - LPG

Liquified Petroleum Gas Combustion
Small Combustion Sources (0.3-10MMBtu/hr)

Heat Content of LPG	9.15E+07	Btu/1000 gal (AP-42, Section 1.5.3.1)
Heat Input of Source	3.60E+06	Btu/hr
Sulfur Content =	15	grains/100 ft^3 (per applicants submittal)
Annual operations =	8760	hours

Pollutant	Emission Factor (lb/1000 gal)	Emission Rate (lb/h)	Emission Rate (t/yr)
Particulate Matter	0.4	0.016	0.069
Sulfur Dioxide	0.1S[b]	0.059	0.258
Nitrogen Oxides	14	0.551	2.413
Carbon Monoxide	1.9	0.075	0.327
VOC[c]	0.5	0.020	0.086

a) AP-42, Section 1.5, Table 1.5-1

b) Sulfur Content of fuel in grains per 100 ft^3

c) Volatile organic compounds (assumed to be equal to total organic compounds)

Larsen Farms

Heater

Natural Gas Combustion	1.20E+06	Btu/hr	(per applicant's submittal)
Heat Content of Natural Gas	1020	Btu/ft^3	(per applicant's submittal)

Emission Factors are from AP-42 Section 1.4, 7/98 (< 100E6 Btu/hr)

Annual hours of operation 8760

Pollutant	Emission F[illegible] (lb/MMscf)	Emission [illegible]	[illegible]	[illegible]
NOx	100	1.18E-01	3.53E-01	1.55E+00
CO	84	9.88E-02	2.96E-01	1.30E+00
PM	7.6	8.94E-03	2.68E-02	1.17E-01
SO2	0.6	7.06E-04	2.12E-03	9.28E-03
VOC	5.5	6.47E-03	1.94E-02	8.50E-02
2-Methylnaphthalene	2.45E-05	2.88E-08	8.65E-08	3.79E-07
3-Methylchloranthrene	1.80E-06	2.12E-09	6.35E-09	2.78E-08
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.88E-08	5.65E-08	2.47E-07
Acenaphthene	1.80E-06	2.12E-09	6.35E-09	2.78E-08
Acenaphthylene	1.80E-06	2.12E-09	6.35E-09	2.78E-08
Anthracene	2.40E-06	2.82E-09	8.47E-09	3.71E-08
Benz(a)anthracene (1)	1.80E-06	2.12E-09	6.35E-09	2.78E-08
Benzene	2.10E-03	2.47E-06	7.41E-06	3.25E-05
Benz(a)pyrene (1)	1.20E-06	1.41E-09	4.24E-09	1.86E-08
Benzo(b)fluoranthene (1)	1.80E-06	2.12E-09	6.35E-09	2.78E-08
Benzo(g,h,i)perylene	1.20E-06	1.41E-09	4.24E-09	1.86E-08
Benzo(k)fluoranthene (1)	1.80E-06	2.12E-09	6.35E-09	2.78E-08
Butane	2.10E+00	2.47E-03	7.41E-03	3.25E-02
Chrysene (1)	1.80E-06	2.12E-09	6.35E-09	2.78E-08
Dibenzo(a,h)anthracene (1)	1.20E-06	1.41E-09	4.24E-09	1.86E-08
Dichlorobenzene	1.20E-03	1.41E-06	4.24E-06	1.86E-05
Ethane	3.10E+00	3.65E-03	1.09E-02	4.79E-02
Fluoranthene	3.00E-06	3.53E-09	1.06E-08	4.64E-08
Fluorene	2.80E-06	3.29E-09	9.88E-09	4.33E-08
Formaldehyde	7.50E-02	8.82E-05	2.65E-04	1.16E-03
Hexane	1.80E+00	2.12E-03	6.35E-03	2.78E-02
Indeno(1,2,3-cd)pyrene (1)	1.80E-06	2.12E-09	6.35E-09	2.78E-08
Naphthalene	6.10E-04	7.18E-07	2.15E-06	9.43E-06
PAH (2)	1.14E-05	1.34E-08	4.02E-08	1.76E-07
Pentane	2.60E+00	3.06E-03	9.18E-03	4.02E-02
Phenanathrene	1.70E-05	2.00E-08	6.00E-08	2.63E-07
Propane	1.60E+00	1.88E-03	5.65E-03	2.47E-02
Pyrene	5.00E-06	5.88E-09	1.76E-08	7.73E-08
Toluene	3.40E-03	4.00E-06	1.20E-05	5.26E-05
Arsenic	2.00E-04	2.35E-07	7.06E-07	3.09E-06
Barium	4.40E-03	5.18E-06	1.55E-05	6.80E-05
Beryllium	1.20E-05	1.41E-08	4.24E-08	1.86E-07
Cadmium	1.10E-03	1.29E-06	3.88E-06	1.70E-05
Chromium	1.40E-03	1.65E-06	4.94E-06	2.16E-05
Cobalt	8.40E-05	9.88E-08	2.96E-07	1.30E-06
Copper	8.50E-04	1.00E-06	3.00E-06	1.31E-05
Manganese	3.80E-04	4.47E-07	1.34E-06	5.87E-06
Mercury	2.60E-04	3.06E-07	9.18E-07	4.02E-06
Molybdenum	1.10E-03	1.29E-06	3.88E-06	1.70E-05
Nickel	2.10E-03	2.47E-06	7.41E-06	3.25E-05
Selenium	2.40E-05	2.82E-08	8.47E-08	3.71E-07
Vanadium	2.30E-03	2.71E-06	8.12E-06	3.56E-05
Zinc	2.90E-02	3.41E-05	1.02E-04	4.48E-04

(1) Compounds which make up PAH

(2) Sum of emission factors which make up PAH

Larsen Farms

Heater - LPG

Liquified Petroleum Gas Combustion
Small Combustion Sources (0.3-10MMBtu/hr)

Heat Content of LPG =	9.15E+07	Btu/1000 gal (AP-42, Section 1.5.3.1)
Heat Input of Source =	1.20E+06	Btu/hr
Sulfur Content =	15	grains/100 ft^3 (per applicant's submittal)
Annual operations =	8760	hours

Pollutant	Emission Factor (lb/1000 gal)	Emission Rate (lb/hr)	Emission Rate (t/yr)
Particulate Matter	0.4	0.005	0.023
Sulfur Dioxide	0.1S[b]	0.020	0.086
Nitrogen Oxides	14	0.184	0.804
Carbon Monoxide	1.9	0.025	0.109
VOC[c]	0.5	0.007	0.029

a) AP-42, Section 1.5, Table 1.5-1

b) Sulfur Content of fuel in grains per 100 ft^3

c) Volatile organic compounds (assumed to be equal to total organic compounds)

Attachment B

Summary of Emission Estimates

Emissions Summary Table

Source	PM		PM_{10}		SO_2		CO		NO_x		VOC	
	Lb/hr	T/yr	Lb/hr	T/yr	Lb/hr	T/yr	Lb/hr	T/yr	Lb/hr	T/yr	Lb/hr	T/yr
Boiler (maximum emissions)	8.3	29.0	8.3	29.0	69.8	244	11.86	51.94	41.8	146	1.14	3.98
Drum Dryer 1	0.67	2.92	0.29	1.28								
Drum Dryer 2	0.67	2.92	0.29	1.28								
Drum Dryer 3	0.67	2.92	0.29	1.28								
Drum Dryer 4	0.67	2.92	0.29	1.28								
Drum Dryer 5	0.67	2.92	0.29	1.28								
Drum Dryer 6	0.67	2.92	0.29	1.28								
Drum Dryer 7	0.67	2.92	0.29	1.28								
Drum Dryer 8	0.67	2.92	0.29	1.28								
Drum Dryer 9	0.67	2.92	0.29	1.28								
Drum Dryer 10	0.67	2.92	0.29	1.28								
Drum Dryer 11	0.67	2.92	0.29	1.28								
Drum Dryer 12	0.67	2.92	0.29	1.28								
National Dryer Process Emissions (total of 4)	3.75	16.43	3.75	16.43								
Fluidized Bed Dryer (process plus combustion)	1.68	7.35 (7.38)[a]	0.76	3.33	0.07	0.32	0.37 (0.38)[a]	1.62 (1.66)[a]	0.69 (0.67)[a]	3.02 (2.94)[a]	0.025 (0.02)[a]	0.11
Flake Packaging Bulk Line	0.129	0.565	0.065	0.283								
Flake Packaging Line	0.065	0.283	0.032	0.141								
Flake Packaging Torit Line	0.86	3.767	0.43	1.883								
Flake Packaging Drum Negative Air Baghouse	0.194	0.848	0.097	0.424								
National Dryer A1 Combustion Emissions	0.03	0.12	0.03	0.12	0.06	0.26	0.3	1.31 (1.32)[a]	0.55	2.4	0.02	0.09
National Dryer A2 Combustion Emissions	0.03	0.12	0.03	0.12	0.06	0.26	0.3	1.31 (1.32)[a]	0.55	2.4	0.02	0.09
National Dryer B Combustion Emissions	0.03	0.12	0.03	0.12	0.06	0.26	0.3	1.31 (1.32)[a]	0.55	2.4	0.02	0.09
National Dryer C Combustion Emissions	0.03	0.12	0.03	0.12	0.06	0.26	0.3	1.31 (1.32)[a]	0.55	2.4	0.02	0.09
Heaters (total of 3) Combustion Emissions	0.03	0.12	0.03	0.12	0.06	0.26	0.3	1.31 (1.32)[a]	0.55 (0.68)[a]	2.42 (3.0)[a]	0.02	0.09

a) Values in parentheses are values which the applicant provided which are different than DEQ's confirmatory emission estimates

Attachment C

Toxic Air Pollutant Screening Analysis

Larsen Farms

Toxic Air Pollutant Screening Analysis
All Units Combusting Natural Gas

Pollutant	[illegible] Boiler (lb/hr)	Four National Dryers (lb/hr)	Fluidized Bed Dryer (lb/hr)	[illegible] Heaters (lb/hr)	[illegible] Emissions (lb/hr)	Screening Emission [illegible] (lb/hr)	Meets or Exceeds Screening Value
2-Methylnaphthalene	3.39E-06	3.46E-07	1.08E-07	8.65E-08	3.93E-06		
3-Methylchloranthrene	2.54E-07	2.54E-08	7.94E-09	6.35E-09	2.94E-07		
7,12-Dimethylbenz(a)anthracne	2.26E-06	2.26E-07	7.06E-08	5.65E-08	2.61E-06		
Acenaphthene	2.54E-07	2.54E-08	7.94E-09	6.35E-09	2.94E-07		
Acenaphylene	2.54E-07	2.54E-08	7.94E-09	6.35E-09	2.94E-07		
Anthracene	3.39E-07	3.39E-08	1.06E-08	8.47E-09	3.92E-07		
Benz(a)anthracene[1]	2.54E-07	2.54E-08	7.94E-09	6.35E-09	2.94E-07		
Benzene	2.96E-04	2.96E-05	9.26E-06	7.41E-06	3.43E-04	8.00E-04	Meets
Benzo(a)pyrene[1]	1.69E-07	1.69E-08	5.29E-09	4.24E-09	1.96E-07	2.00E-06	Meets
Benzo(b)fluoranthene[1]	2.54E-07	2.54E-08	7.94E-09	6.35E-09	2.94E-07		
Benzo(g,h,l)perylene	1.69E-07	1.69E-08	5.29E-09	4.24E-09	1.96E-07		
Benzo(k)fluoranthene[1]	2.54E-07	2.54E-08	7.94E-09	6.35E-09	2.94E-07		
Butane	2.96E-01	2.96E-02	9.26E-03	7.41E-03	3.43E-01		
Chrysene[1]	2.54E-07	2.54E-08	7.94E-09	6.35E-09	2.94E-07		
Dibenzo(a,h)anthracene[1]	1.69E-07	1.69E-08	5.29E-09	4.24E-09	1.96E-07		
Dichlorobenzene	1.69E-04	1.69E-05	5.29E-06	4.24E-06	1.96E-04	0.333	Meets
Ethane	4.38E-01	4.38E-02	1.37E-02	1.09E-02	5.06E-01		
Fluoranthene	4.24E-07	4.24E-08	1.32E-08	1.06E-08	4.90E-07		
Fluorene	3.95E-07	3.95E-08	1.24E-08	9.88E-09	4.57E-07		
Formaldehyde	1.06E-02	1.06E-03	3.31E-04	2.65E-04	1.22E-02	5.10E-04	Exceeds
Hexane	2.54E-01	2.54E-02	7.94E-03	6.35E-03	2.94E-01	12	Meets
Ideno(1,2,3-cd)pyrene[1]	2.54E-07	2.54E-08	7.94E-09	6.35E-09	2.94E-07		
Naphthalene	8.61E-05	8.61E-06	2.69E-06	2.15E-06	9.96E-05	3.33	Meets
PAH[2]	1.61E-06	1.61E-07	5.03E-08	4.02E-08	1.86E-06	9.10E-05	Meets
Pentane	3.67E-01	3.67E-02	1.15E-02	9.18E-03	4.24E-01	118	Meets
Phenanathrene	2.40E-06	2.40E-07	7.50E-08	6.00E-08	2.78E-06		
Propane	2.26E-01	2.26E-02	7.06E-03	5.65E-03	2.61E-01		
Pyrene	7.06E-07	7.06E-08	2.21E-08	1.76E-08	8.16E-07		
Toluene	4.80E-04	4.80E-05	1.50E-05	1.20E-05	5.55E-04	25	Meets
Arsenic	2.82E-05	2.82E-06	8.82E-07	7.06E-07	3.26E-05	1.50E-06	Exceeds
Barium	6.21E-04	6.21E-05	1.94E-05	1.55E-05	7.18E-04	0.033	Meets
Beryllium	1.69E-06	1.69E-07	5.29E-08	4.24E-08	1.96E-06	2.80E-05	Meets
Cadmium	1.55E-04	1.55E-05	4.85E-06	3.88E-06	1.80E-04	3.76E-06	Exceeds
Chromium	1.98E-04	1.98E-05	6.18E-06	4.94E-06	2.29E-04	3.30E-02	Meets
Cobalt	1.19E-05	1.19E-06	3.71E-07	2.96E-07	1.37E-05	0.0033	Meets
Copper	1.20E-04	1.20E-05	3.75E-06	3.00E-06	1.39E-04	0.013	Meets
Manganese	5.36E-05	5.36E-06	1.68E-06	1.34E-06	6.20E-05	0.067	Meets
Mercury	3.67E-05	3.67E-06	1.15E-06	9.18E-07	4.24E-05	0.003	Meets
Molybdenum	1.55E-04	1.55E-05	4.85E-06	3.88E-06	1.80E-04	0.333	Meets
Nickel	2.96E-04	2.96E-05	9.26E-06	7.41E-06	3.43E-04	2.70E-05	Exceeds
Selenium	3.39E-06	3.39E-07	1.06E-07	8.47E-08	3.92E-06	0.013	Meets
Vanadium	3.25E-04	3.25E-05	1.01E-05	8.12E-06	3.75E-04		
Zinc	4.09E-03	4.09E-04	1.28E-04	1.02E-04	4.73E-03	0.667	Meets

Larsen Farms

Toxic Air Pollutant Screening Analysis
Boiler Combusting Fuel Oil and all Other Sources Combusting Natural Gas

Pollutant	[illegible] Boiler (lb/hr)	Four [illegible] Dryers (lb/hr)	Fluidized Bed Dryers (lb/hr)	[illegible] (lb/hr)	[illegible] Emissions (lb/hr)	Screening Emission Level (EL) [illegible]	Meets/ Exceeds Screening Level
1,1,1-Trichloroethane	2.10E-04				2.10E-04		
2-Methylnaphthalene		3.46E-07	1.08E-07	8.65E-08	5.40E-07		
3-Methylchloranthrene		2.54E-08	7.94E-09	6.35E-09	3.97E-08		
7,12-Dimethylbenz(a)anthracne		2.26E-07	7.06E-08	5.65E-08	3.53E-07		
Acenaphthene	1.88E-05	2.54E-08	7.94E-09	6.35E-09	1.88E-05		
Acenaphylene	2.25E-07	2.54E-08	7.94E-09	6.35E-09	2.65E-07		
Anthracene	1.08E-06	3.39E-08	1.06E-08	8.47E-09	1.13E-06		
Benz(a)anthracene	3.56E-06	2.54E-08	7.94E-09	6.35E-09	3.60E-06		
Benzene	1.90E-04	2.96E-05	9.26E-06	7.41E-06	2.36E-04	8.00E-04	Meets
Benzo(a)pyrene		1.69E-08	5.29E-09	4.24E-09	2.65E-08	2.00E-06	Meets
Benzo(b)fluoranthene		2.54E-08	7.94E-09	6.35E-09	3.97E-08		
Benzo(b,k)fluoranthene	1.32E-06				1.32E-06		
Benzo(g,h,l)perylene	2.01E-06	1.69E-08	5.29E-09	4.24E-09	2.04E-06		
Benzo(k)fluoranthene		2.54E-08	7.94E-09	6.35E-09	3.97E-08		
Butane		2.96E-02	9.26E-03	7.41E-03	4.63E-02		
Chrysene	2.12E-06	2.54E-08	7.94E-09	6.35E-09	2.16E-06		
Dibenzo(a,h)anthracene	1.48E-06	1.69E-08	5.29E-09	4.24E-09	1.51E-06		
Dichlorobenzene		1.69E-05	5.29E-06	4.24E-06	2.65E-05	0.333	Meets
Ethane		4.38E-02	1.37E-02	1.09E-02	6.84E-02		
Ethylbenzene	5.65E-05				5.65E-05	29	Meets
Fluoranthene	4.30E-06	4.24E-08	1.32E-08	1.06E-08	4.37E-06		
Fluorene	3.97E-06	3.95E-08	1.24E-08	9.88E-09	4.03E-06		
Formaldehyde	2.93E-02	1.06E-03	3.31E-04	2.65E-04	3.10E-02	5.10E-04	Exceeds
Hexane		2.54E-02	7.94E-03	6.35E-03	3.97E-02	12	Meets
Ideno(1,2,3-cd)pyrene	1.90E-06	2.54E-08	7.94E-09	6.35E-09	1.94E-06		
Naphthalene	1.00E-03	8.61E-06	2.69E-06	2.15E-06	1.01E-03	3.33	Meets
o-Xylene	9.69E-05				9.69E-05		
PAH[2]	9.07E-06	1.61E-07	5.03E-08	4.02E-08	9.32E-06	9.10E-05	Meets
Pentane		3.67E-02	1.15E-02	9.18E-03	5.74E-02	118	Meets
Phenanathrene	9.33E-06	2.40E-07	7.50E-08	6.00E-08	9.71E-06		
Propane		2.26E-02	7.06E-03	5.65E-03	3.53E-02		
Pyrene	3.78E-06	7.06E-08	2.21E-08	1.76E-08	3.89E-06		
Toluene	5.51E-03	4.80E-05	1.50E-05	1.20E-05	5.59E-03	25	Meets
Antimony	4.67E-03				4.67E-03	0.033	Meets
Arsenic	1.17E-03	2.82E-06	8.82E-07	7.06E-07	1.17E-03	1.50E-06	Exceeds
Barium	2.28E-03	6.21E-05	1.94E-05	1.55E-05	2.38E-03	0.033	Meets
Beryllium	2.47E-05	1.69E-07	5.29E-08	4.24E-08	2.50E-05	2.80E-05	Meets
Cadmium	3.54E-04	1.55E-05	4.85E-06	3.88E-06	3.78E-04	3.76E-06	Exceeds
Chloride	3.08E-01				3.08E-01		
Chromium	7.51E-04				7.51E-04	3.30E-02	Meets
Chromium VI[1]	2.20E-04	1.98E-05	6.18E-06	4.94E-06	7.51E-04	5.60E-07	Exceeds
Cobalt	5.35E-03	1.19E-06	3.71E-07	2.96E-07	5.35E-03	0.0033	Exceeds
Copper	1.56E-03	1.20E-05	3.75E-06	3.00E-06	1.58E-03	0.013	Meets
Fluoride	3.32E-02				3.32E-02	0.167	Meets
Lead	1.34E-03				1.34E-03		
Manganese	2.67E-03	5.36E-06	1.68E-06	1.34E-06	2.68E-03	0.067	Meets
Mercury	1.00E-04	3.67E-06	1.15E-06	9.18E-07	1.06E-04	0.003	Meets
Molybdenum	7.00E-04	1.55E-05	4.85E-06	3.88E-06	7.24E-04	0.333	Meets
Nickel	7.51E-02	2.96E-05	9.26E-06	7.41E-06	7.51E-02	2.70E-05	Exceeds
Phosphorus	8.41E-03				8.41E-03	7.00E-03	Exceeds
Selenium	6.07E-04	3.39E-07	1.06E-07	8.47E-08	6.08E-04	0.013	Meets
Vanadium	2.83E-02	3.25E-05	1.01E-05	8.12E-06	2.84E-02		
Zinc	2.59E-02	4.09E-04	1.28E-04	1.02E-04	2.65E-02	0.667	Meets

1) Assumes all chromium emitted from natural gas combustion is Chromium VI

Attachment D

Combustion Evaluation

Combustion Evaluation

Larsen Farms - 144 MMBtu/hr Boiler (#6 Fuel Oil)
Firing rate is 898 gal/hr
Density of fuel is 8.212 lb/gal*
*Pollution Control, Student Manual, March 1994, Table 5-3

Fuel Data (% by weight)
#6 Fuel oil[1]

S	0.5
N2	0.92
C	85.7
H2	10.5
H20	0
O2	0.92

Fuel burned (lb/hr)	7374.4
Excess air (%)[a]	15
Stk temp (F)[b]	585
Stk press (atm)	0.883
Elevation (ft)	4800

a) Based on engineering judgement
b) Given by applicant in application

Combustion Air Required

	O2 lb.mole	N2 lb.mole
S	1.15	4.32
N2	0.00	0
C	526.17	1979.41
H2	192.14	722.80
O2	-2.12	
	717.34	2706.54

stioc. comb air = 3623.4389 lb.mole/hr
stoic. dry comb air = 3233.8599 lb.mole/hr

Flue Products

	lb.mole	lb/hr
SO2	1.15	73.61
N2	3114.94	87218.34
CO2	526.17	23151.60
H2O(comb)	387.16	6968.81
O2	107.60	3443.23
H2O(fuel)	0.00	0.00
dry	3749.86	
wet	4137.02	

	Flow[2]	IDAPA Flow[3]
Volume of flue gas (acfm)	59584.6	
Volume of flue gas (sdcfm)	23730.6	
Volume of flue gas (dscfm@7%O2)	30697.7	36563.5
Volume of flue gas (dscfm@15%O2)	71628.1	85314.9
Volume of flue gas (dscfm@8%02)	33059.1	39376.1
Volume of flue gas (dscfm@3%02)	23876.0	28438.3
Volume of flue gas (dscfm@10%02)	39069.8	46535.4

1) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994,
2) Standard conditions based on a pressure of 1.0 atmospheres
3) Standard conditions corrected for altitude per IDAPA 58.01.01.680

Stack Diameter (feet) = 6.65
Stack velocity (ft/s) = 28.61

Attachment E

Particulate Matter Grain Loading

[redacted]

Particulate Matter Grain Loading

Calculating the particulate matter grain loading from the 144.19 MMBtu boiler while combusting residual fuel oil.

The filterable particulate matter emission factor is from AP-42 Table 1.3-1

$$PM = 9.19(S) + 3.22 \ \frac{lb}{10^3 \text{ gallons}}$$

where S is the percent sulfur

The applicant will limit sulfur to 0.5 percent

$$PM = 9.19(.5) + 3.22 \ \frac{lb}{10^3 \text{ gallon}} = 7.815 \ \frac{lb}{10^3 \text{ gallon}}$$

The applicant proposes to combust 898 gallons per hour.

$$PM = \left(7.815 \ \frac{lb}{10^3 \text{ gal}}\right)\left(898 \ \frac{gal}{hr}\right) = 7.017 \ \frac{lb}{hr}$$

Gas flowrate is $28{,}438.3 \ \frac{ft^3}{min}$ @ 3% O_2

Grain loading is:

$$\frac{7.017 \ \frac{lb}{hr} \ \frac{hr}{60 min} \ \frac{7000 gr}{1 lb}}{28{,}438.3 \ \frac{ft^3}{min}} = 0.029 \ \frac{gr}{ft^3} \text{ @ } 3\% \ O_2$$

LARSEN FARMS

Premium Potato Products
P.O. Box 188 Hamer, ID 83425
1-800-297-6724 • 1-208-374-5600
Fax 1-208-374-5497

C: Mike IFRO
Ken
Route to:
– Marilyn
– Pat R, S.F.

May 17, 2004

Mike Simon
Air Quality Division
Idaho Department of Environmental Quality
1410 North Hilton
Boise, Idaho 83706-1255

RE: Additional Information for the Prevention of Significant Deterioration (PSD) Analysis for Blaine Larsen Farms Dehydration Division

Dear Mr. Simon:

Blaine Larsen Farms Dehydration Division (BLF Dehydration Division) is submitting additional information as requested by the Idaho Department of Environmental Quality (DEQ) on May 5, 2004. The information provided in this letter is to further address PSD applicability.

The information requested by DEQ included the following:

- The energy capacity of the originally installed boilers in 1989.
  - The BTU content of the steam used to operate the original drum dryers, cooker and peeler.
- The dates that the old boilers were changed or removed and when the new one was installed.
  - The status of the oil heaters and tanks in 1992, and whether this precluded the new boiler from operating on oil.
- The energy requirements of the drum dryers, peeler, and cooker at the time the original boilers were installed.

Note that the original boilers were installed in March 1989 and the tanks, piping and other equipment were installed in time for the start up of the new crop in September 1989.

Original Boiler Energy Capacity

The old boilers were water tube boilers manufactured by Babcock and Wilcox.[1] They were eight years old when they were installed. The capacity of each boiler was 30,000 lbs/hr of steam.

---

[1] BLF Dehydration searched extensively for the nameplates and model numbers but was unsuccessful in finding them.

RECEIVED
MAY 18 2004
Department of Environmental Quality

They operated at 120 psi and 350°F. Based on enthalpy of 1,196 BTU/lb at 120 psi and 350°F, the maximum capacity of each boiler converts to 36 MMBTU/hr.

Dates of Original Boiler Change or Removal and New Boiler Installation

The original boilers were converted completely to propane, which occurred to the best of our knowledge in January 1992. Immediately after this conversion, it was not possible to operate on oil. At that time the oil train (i.e., piping, valves, controls, etc.) was completely removed to accommodate propane valves and other propane related equipment.

In 1996, the new propane Wabash boiler, model number NS-F-89-ECON, Serial No. D-3456, was installed. The old and new boilers could not operate together as there was a complete renovation of the steam system. The steam pipes were changed to accommodate new peelers so there was no connection to the original boilers.[2]

Note that the oil tanks were removed by June 1992 to the best of our knowledge. .

Energy Requirements of Plant Operating Under Original Boilers

At the time the original facility was constructed in 1989, the plantwide energy requirements of the boilers are as follows:

- 4 used drum dryers
  These drums had dimensions of 5 feet x 16 feet. The drum dryers were made by Overton and Blonox, which are no longer in business. However, according to Idaho Steel, the current drum dryer manufacturer, drum dryers sized at 5 feet x 17 feet would require slightly more energy and consume a maximum of 4,000 lbs/hr steam.[3] For this analysis, an energy requirement of 4,000 lbs/hr steam per drum will be used.

- 1 cooker
  In the December 2, 2003 PSD analysis letter submitted to DEQ, BLF Dehydration Division estimated the cooker energy requirements at 2,200 lbs/hr steam. Upon further examination, the cooker, manufactured by Idaho Steel, did not require additional steam from the boiler.[4] The steam for the cooker originated from the flash steam of the drum dryers.

  Note this is in contrast to the current cooker, where steam comes directly from the boiler.

- 1 small steam peeler

---

[2] In 1996, the full capacity of the new propane boiler had the potential to be utilized to run the plant. After the new propane boiler was installed, two more steam peelers were added at 60,000 lb/hr capacity each. However, energy requirements of the steam peelers are not necessary for calculating the potential to emit in 1996.
[3] Based on a conversation with Delynn Bradshaw of Idaho Steel Products on May 10, 2004.
[4] Based on a conversation with Delynn Bradshaw of Idaho Steel Products on May 10, 2004.

The steam peeler was manufactured by Columbia Foods. The steam requirement is rated at 1 lb steam/15 lbs product. Based on a capacity of 30,000 lb/hr potatoes, the energy requirement= 2,000 lbs/hr.[5]

From 1989 to 1992 the plant had a total of 18,000 lbs/hr of steam requirements. The boiler at that time operated at 120 psi and 350°F producing steam at 1,196 BTU/lb (enthalpy). Based on 1,196 BTU/lb of steam, the plant had a total requirement of 21,528,000 BTU/hr. The fuel consumption for each boiler, based on 155,000 BTU/gal of #6 oil, is calculated as follows:

- 21,528,000 BTU/hr / 155,000 BTU/gal of #6 oil = 139 gal/hr #6 oil

In 1992 the boilers were converted to propane. The steam demand increased as an additional drum dryer (4,000 lb/hr steam); the steam demand increased only after the boiler was converted to propane. The steam requirements for the plant increased by 4,000 lbs/hr to 22,000 lbs/hr or 26,312,000 BTU/hr. Based on 92,000 BTU/gal propane, the fuel consumption for each boiler is calculated as follows:

- 26,312,000 BTU/hr / 92,000 BTU/gal propane = 286 gal/hr propane

Updated PSD Applicability Analysis

The enclosed updated spreadsheet shows the potential to emit (PTE) facility-wide, and the PTE change, for each year that equipment was installed or modified, prior to the permit application submittal. As shown in the spreadsheet, the facility is not a PSD major source nor is BLF Dehydration Division requesting emission limits in the permit application that would make the source PSD major.

Compared to the originally submitted spreadsheet on December 2, 2003, the updated spreadsheets show the following:

- Credit for removal of old boilers
- Old and new boilers were not operating at the same time
- Updated drum dryer emissions (inadvertently based on National Dryers in original submittal)
- Worksheets showing each emission source calculation

[5] Based on a conversation with Dan Herz of Columbia Foods on May 10, 2004.

Certification

Should you have any questions regarding this information submitted, please contact Jan Nel, Plant Manager, of BLF Dehydration Division at 208.374.5592 or Daniel Heiser of JBR Environmental Consultants, Inc. at 208.853.0883.

I certify that based on information and belief formed after reasonable inquiry, the statements and information enclosed are true, accurate and complete to the best of my knowledge.

Respectfully Submitted,

JAN Nel. PH

Brandon Larsen
President
Blaine Larsen Farms

cc: Daniel Heiser, JBR

Enclosures

BLF Dehydration Division
Potential to Emit Calculations 1989 - Present
For PSD Applicability

Date	Source	PM ton/yr	PM-10 ton/yr	VOC ton/yr	SO_2 ton/yr	NOx ton/yr	CO ton/yr	Comments
1989	Residual Boiler (8 years old; installed March, 1989)	12.66	12.66	0.78	167.27	33.49	3.04	Only one Boiler was used at a time as there were only 4 Drum Dryers and one small peeler using steam.
	Residual Boiler (8 years old; installed March, 1989)	0.00	0.00	0.00	0.00	0.00	0.00	Start up occurred September 1989
	Flake Packaging Bulk Line	0.57	0.28					
	Flake Packaging	0.28	0.14					
	Propane Heaters	0.12	0.12	0.09	0.26	3.00	1.32	
	Tanks (installed September, 1989)			0.09				
	Four Used Drum Dryers*	11.68	5.14					
PTE Change		25.31	18.35	0.96	167.53	36.48	4.37	
1989 Total PTE		25.31	18.35	0.96	167.53	36.48	4.37	

BLF Dehydration Division
Potential to Emit Calculations 1989 - Present
For PSD Applicability

Date	Source	PM ton/yr	PM-10 ton/yr	VOC ton/yr	SO_2 ton/yr	NOx ton/yr	CO ton/yr	Comments
1990	National Dryer Fan A1	4.13	4.13	0.09	0.26	2.39	1.32	
	National Dryer Fan A2	4.13	4.13	0.09	0.26	2.39	1.32	
	National Dryer Fan B	4.13	4.13	0.09	0.26	2.39	1.32	
	National Dryer Fan C	4.13	4.13	0.09	0.26	2.39	1.32	
PTE Change		16.53	16.53	0.35	1.02	9.57	5.30	
Cumulative Total PTE		41.85	34.88	1.30	168.55	46.05	9.67	
Jan-92	Boilers Ceased Burning Oil	(12.66)	(12.66)	(0.78)	(167.27)	(33.49)	(3.04)	
	Boiler Conversion to Propane	0.75	0.75	0.63	1.88	23.80	4.01	
	1 Drum Dryer	2.92	1.28					
PTE Change		-8.99	-10.63	-0.15	-165.39	-9.68	0.96	
Cumulative Total PTE		32.85	24.25	1.15	3.16	36.36	10.63	
1996	Old Propane Boilers Ceased Operating	(0.75)	(0.75)	(0.63)	(1.88)	(23.80)	(4.01)	It was not possible to operate the old and new boilers together as the steam pipes were changed to accommodate two new peelers which replaced the old steam peeler; there was no connection to the old boilers. There was a complete renovation of the steam system.
	New Propane Boiler	4.25	4.25	3.54	10.61	134.44	22.64	Maximum boiler capacity used.
	Flake Packaging Torit	3.77	1.88					
PTE Change		7.26	5.38	2.91	8.73	110.64	18.63	
Cumulative Total PTE		40.11	29.63	4.06	11.89	147.00	29.27	

BLF Dehydration Division
Potential to Emit Calculations 1989 - Present
For PSD Applicability

Date	Source	PM ton/yr	PM-10 ton/yr	VOC ton/yr	SO_2 ton/yr	NOx ton/yr	CO ton/yr	Comments
1997	Removal of Old Drum Dryers	(14.60)	(6.42)					
	Drum Dryers 1 - 12	35.04	15.42					
	Flake Packaging Drum Negative Air Baghouse	0.85	0.42					
PTE Change		21.29	9.42	0.00	0.00	0.00	0.00	
Cumulative Total PTE		61.40	39.05	4.06	11.89	147.00	29.27	
1998	Fluidized Bed Dryer	7.38	3.33	0.47	0.32	2.94	1.66	
PTE Change		7.38	3.33	0.47	0.32	2.94	1.66	
Cumulative Total PTE		68.78	42.38	4.54	12.21	149.95	30.92	

* Emission calculations based on flakers

Flake Packaging

PM Emission Factor is Based on Past Experience with Similar Facilities

	Uncontrolled PM, lb/ton	Uncontrolled PM-10, lb/ton[a]	Controlled PM, lb/ton[b]	Controlled PM-10, lb/ton[b]	Throughput, lb/hr	Throughput, tpy[c]	PM, lb/hr	PM, tpy	PM-10, lb/hr	PM-10, tpy
Flake Packaging Bulk Line	2.15	1.075	0.0215	0.01075	12,000	52,560	0.129	0.57	0.065	0.283
Flake Packaging Line	2.15	1.075	0.0215	0.01075	6,000	26,280	0.065	0.28	0.032	0.141
Flake Packaging Torit Line	2.15	1.075	0.2150	0.10750	8,000	35,040	0.860	3.77	0.430	1.883
Flake Packaging Drum Negative Air Baghouse	2.15	1.075	0.0215	0.01075	18,000	78,840	0.194	0.85	0.097	0.424
Total							1.05	4.61	0.53	2.31

[a]PM-10 emission factor assumed to be 44% of PM emission factor per AP-42, Appendix B.1, Section 9.9.2.

[b]Baghouse control = 99%; for Torit line, it is assumed that cyclone control = 90%.

[c]Annual production = 8,760 hours per year.

SPACE HEATERS

Criteria Pollutant Estimates, AP-42, Tables 1.5-1, 10/96

Criteria Pollutant Estimates, AP-42, Tables 1.4-1 and 1.4-2, 9/98

Propane Heaters 1, 2 and 3

Propane

	Pollutant				
	SO_2	NO_X	CO	PM	VOC[a]
Emission Factor, lb/1,000 gal	0.1 S[b]	14	1.9	0.4	0.5
S = 15					
Maximum gal/hr 39					
Maximum hrs/yr 8,760					
Emissions, lb/hr No control	0.06	0.55	0.07	0.02	0.02
Emissions, ton/yr No control	0.26	2.39	0.32	0.07	0.09

Natural Gas

	Pollutant				
	SO_2	NO_X	CO	PM/PM-10	VOC
Emission Factor, lb/10^6 scf	0.6	190	84	7.6	5.5
Maximum MMscf/hr 3.60E-03					
Maximum hrs/yr 8,760					
Emissions, lb/hr No control	0.002	0.68	0.30	0.03	0.02
Emissions, ton/yr No control	0.009	3.00	1.32	0.12	0.09

[a]VOC assumed to be equal to TOC.
[b]S = sulfur fuel content in grains/100 ft^3, assumed to be 15 (per the Gas Processors Association Engineering Data Book, standard for commercial grade propane).

Total Maximum Emissions:

	PM, lb/hr	PM, ton/yr	PM-10, lb/hr	PM-10, ton/yr	SO_2, lb/hr	SO_2, ton/yr	CO, lb/hr	CO, ton/yr	NOx, lb/hr	NOx, ton/yr	VOC, lb/hr	VOC, ton/yr
Propane Heaters	0.03	0.12	0.03	0.12	0.06	0.26	0.30	1.32	0.68	3.00	0.02	0.09

Note: Capacity = 1.2 MMBTU/propane heater

Fluidized Bed Dryer

Criteria Pollutant Estimates for Fuel Combustion, <100 MMBTU/hr (Source: AP-42, Tables 1.4-1, 1.4-2, 9/98 edition and 1.5-1, 10/96 edition)

Natural Gas

	Pollutant				
	SO_2	NO_X	CO	PM/PM-10	VOC
Emission Factor, lb/10^6 scf	0.6	100	84	7.6	5.5
Maximum MMscf/hr 4.50E-03					
Maximum hrs/yr 8,760					
Emissions, lb/hr No control	0.003	0.45	0.38	0.03	0.02
Emissions, ton/yr No control	0.012	1.97	1.66	0.15	0.11

Propane

	Pollutant				
	SO_2	NO_X	CO	PM/PM-10	VOC[a]
Emission Factor, lb/1,000 gal	0.10 S[b]	14	1.9	0.4	0.5
S = 15					
Maximum gal/hr 48.00					
Maximum hrs/yr 8,760					
Emissions, lb/hr No control	0.07	0.67	0.09	0.02	0.02
Emissions, ton/yr No control	0.32	2.94	0.40	0.08	0.11

Process Emissions

Emission Factors, AP-42, Appendix B.1, Section 9.9.2, 10/86, Cereal Dryer

PM EF, lb/ton	PM-10 EF, lb/ton[c]	Product, lb/hr	Product, tpy[d]	PM, lb/hr	PM, tpy[d]	PM-10, lb/hr	PM-10, tpy[d]
1.65	0.726	2,000	8,760	1.65	7.23	0.73	3.18

Total Maximum Emissions (Combustion + Process Emissions):

PM, lb/hr	PM, ton/yr	PM-10, lb/hr	PM-10, ton/yr	SO_2, lb/hr	SO_2, ton/yr	CO, lb/hr	CO, ton/yr	NOx, lb/hr	NOx, ton/yr	VOC, lb/hr	VOC, ton/yr
1.68	7.38	0.76	3.33	0.07	0.32	0.38	1.66	0.67	2.94	0.11	0.47

FBD size = 4.5 MMBTU/hr

[a]VOC assumed to be equal to TOC.

[b]S = sulfur fuel content in grains/100 ft^3, assumed to be 15 (per the Gas Processors Association Engineering Data Book, standard for commercial grade propane).

[c]This is derived from the AP-42, Appendix B.1, Section 9.9.2 uncontrolled PM-10 emission factor of 0.75 kg/Mg; with PM-10 at 44% of PM, and converting to lb/hr, the PM emission factor is 1.65 lb/ton.

[d]Annual production = 8,760 hours per year.

National Dryer Process Emissions

PM Emission Factor Is Based on Past Experience with Similar Facilities

	Uncontrolled PM/PM-10, lb/ton	Product, ton/hr	Product, tpy	PM/PM-10, lb/hr	PM/PM-10, tpy
National Dryer A1	5.0	0.188	1,643	0.94	4.11
National Dryer A2	5.0	0.188	1,643	0.94	4.11
National Dryer B	5.0	0.188	1,643	0.94	4.11
National Dryer C	5.0	0.188	1,643	0.94	4.11
Total		0.750	6,570	3.75	16.43

Note: Based on total product output of 1,500 lb/hr, and process emissions being divided evenly among the four stacks.

Boiler Propane (for 1996)

Criteria Pollutant Estimates, >100 MMBTU/hr (AP-42, Table 1.5-1, 10/96)

	Pollutant				
	SO_2	NO_X	CO	PM	VOC[a]
Emission Factor, lb/1,000 gal	0.10 S[b]	19	3.2	0.6	0.5
S = 15					
Maximum gal/hr 1,615.50					
Maximum hrs/yr 8,760					
Emissions, lb/hr No control	2.42	30.69	5.17	0.97	0.81
Emissions, ton/yr No control	10.61	134.44	22.64	4.25	3.54

[a]VOC assumed to be equal to TOC.

[b]S = sulfur fuel content in grains/100 ft^3, assumed to be 15 (per the Gas Processors Association Engineering Data Book, standard for commercial grade propane).

Boiler Propane (for 1992)

Criteria Pollutant Estimates, 10 - 100 MMBTU/hr (AP-42, Table 1.5-1, 10/96)

	Pollutant				
	SO_2	NO_X	CO	PM/PM-10	VOC[a]
Emission Factor, lb/1,000 gal	0.10 S[b]	19	3.2	0.6	0.5
S = 15					
Maximum gal/hr 286					
Maximum hrs/yr 8,760					
Emissions, lb/hr No control	0.43	5.43	0.92	0.17	0.14
Emissions, ton/yr No control	1.88	23.80	4.01	0.75	0.63

[a]VOC assumed to be equal to TOC

[b]S = sulfur fuel content in grains/100 ft^3, assumed to be 15 (per the Gas Processors Association Engineering Data Book, standard for commercial grade propane)

Drum Dryers

PM Emission Factor is Based on Past Experience with Similar Facilities

Main Stack	PM, lb/ton	PM-10, lb/ton[a]	Product, lb/hr	Product, tpy[b]	PM, lb/hr	PM, tpy[b]	PM-10, lb/hr	PM-10, tpy[b]
Drum Dryer 1	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Drum Dryer 2	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Drum Dryer 3	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Drum Dryer 4	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Subtotal 1989						11.68		5.14
Drum Dryer 5	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Drum Dryer 6	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Drum Dryer 7	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Drum Dryer 8	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Drum Dryer 9	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Drum Dryer 10	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Drum Dryer 11	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Drum Dryer 12	1.00	0.440	1,333	5,840	0.67	2.92	0.29	1.28
Total drums 1-12:			**16,000**	**70,080**	**8.00**	**35.04**	**3.52**	**15.42**

[a]PM-10 emission factor assumed to be 44% of PM emission factor per AP-42, Appendix B.1, Section 9.9.2.
[b]Annual production = 8,760 hours per year.

Boiler Residual

Criteria Pollutant Estimates, <100 MMBTU/hr (AP-42, Tables 1.3-1, 1.3-2, and 1.3-3, 9/98)

	Pollutant					
	SO_2		NO_X	CO	PM/PM-10[a]	VOC[b]
Emission Factor, lb/1,000 gal	157	S[c]	55	5	9.19S + 3.22 + 1.5	1.28
% S in fuel: 1.75						
100% of Maximum gal/hr 139						
Maximum hrs/yr 8,760						
Emissions, lb/hr No control	38.19		7.65	0.70	2.89	0.18
Emissions, ton/yr No control	167.27		33.49	3.04	12.66	0.78

[a]PM factor is sum of filterable PM plus condensable PM
[b]VOC assumed to be equal to TOC
[c]S = weight % sulfur in fuel

Note: Steam demand for old boilers is 30,000 lb/hr @ T = 350 °F and P = 120 psia
Boiler size = 36 MMBTU/hr Maximum Capacity

Wasp Calculation Results
Temperature= 350.000 Fahrenheit
Pressure= 120.000 PSI abs
Condition= Superheated Vapour

Property	Units	Vapour
Enthalpy	Btu/lb	1196.5
Entropy	Btu/lb.°F	1.5953
Internal Energy	Btu/lb	1112.5
Density / Volume	kg/m3	4.2387
Saturation Pressure	PSI abs	134.61
Viscosity	Pa.s	1.52E-05
Heat Capacity @ Const Press	kJ/kg.K	2.4229
Thermal Conductivity	kW/m.K	3.24E-05
Isentropic Expansion Coeff	-	1.304
Compressibility Factor "Z"	-	0.9402
Boiling Point (@ pressure)	Fahrenheit	341.27

TANKS 4.0
Emissions Report - Summary Format
Tank Identification and Physical Characteristics
Identification
User Identification: Larsen 5-17-04
City: Pocatello
State: Idaho
Company: Larsen
Type of Tank: Vertical Fixed Roof Tank
Description:
Tank Dimensions
Shell Height (ft): 26.00
Diameter (ft): 14.00
Liquid Height (ft): 26.00
Avg. Liquid Height (ft): 13.00
Volume (gallons): 30,000.00
Turnovers: 210.19
Net Throughput (gal/yr): 6,293,000.00
Is Tank Heated (y/n): N
Paint Characteristics
Shell Color/Shade: White/White
Shell Condition: Good
Roof Color/Shade: White/White
Roof Condition: Good
Roof Characteristics
Type: Dome
Height (ft): 0.00
Radius (ft) (Dome Roof): 0.00
Breather Vent Settings
Vacuum Settings (psig): -0.03
Pressure Settings (psig): 0.03
Meteorological Data used in Emissions Calculations: Pocatello, Idaho (Avg Atmospheric Pressure = 12.53 psia)
5/17/2004 12:29:38 PM Page 1
Larsen 5-17-04
Larsen
Vertical Fixed Roof Tank
Pocatello, Idaho
TANKS 4.0
Emissions Report - Summary Format
Liquid Contents of Storage Tank
Liquid
Daily Liquid Surf. Bulk Vapor Liquid Vapor
Temperatures (deg F) Temp. Vapor Pressures (psia) Mol. Mass Mass Mol. Basis for Vapor Pressure
Mixture/Component Month Avg. Min. Max. (deg F) Avg. Min. Max. Weight Fract. Fract. Weight Calculations
Residual oil no. 6 All 48.21 41.93 54.49 46.37 0.0000 0.0000 0.0000 190.0000 387.00 Option 5: A=10.104, B=10475
5/17/2004 12:29:38 PM Page 2
Larsen 5-17-04
Larsen
Vertical Fixed Roof Tank
Pocatello, Idaho
TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals
Annual Emissions Report
Losses(lbs)
Components Working Loss Breathing Loss Total Emissions
Residual oil no. 6 0.24 0.03 0.27
For two tanks, the annual emissions are 0.54 lb/yr.

PM – Process Weight Limitations for Operations
Commenced after 10-1-79, IDAPA 58.01.01.701

Facility: Larsen Farms, Dubois,
T2/PTC T-030514
Date: 1/15/04

Process	Process Weight (lb/hr)	Allowable PM Emissions (lb/hr)	Estimated PM Emissions (lb/hr)	Compliance Demonstrated? (Y / N)
Processes with Process Weight less than 9,250 lb/hr:				
Dryer, drum type, one of twelve	6665	8.86	0.67	Y
Processes with Process Weight greater than 9,250 lb/hr:				
Dryer, fluidized bed type	3200	8.27	1.68	Y
Dryer, National	12,000	11.5	3.75	Y
Flake Packaging (FP) Bulk Line	12,000	11.5	0.13	Y
Flake Packaging Line	6000	9.68	0.065	Y
Flake Packaging Torit Line	8000	10.4	0.86	Y
FP Drum Negative Air Baghouse	18,000	12.7	0.19	Y

Process weight rates are based on information in block 3 of Section 3 of the Permit application forms. See pp 28-33A of the application as amended by letter on 12/16/04.

Estimated PM emissions are based on information in Section 5, Table 5-1, page 50 of the application as amended on 12/16/04.

U.S. Environmental Protection Agency

Compliance Assistance

Search Applicability Determination Index

Determination Detail

Control Number: NN06

Category: NSPS
EPA Office: Region 4
Date: 12/27/1990
Title: Questions Regarding Subpart D(b) Boilers
Recipient: Daniel, Lee A.
Author: Harper, Jewell A.
Comments:

Subparts: Part 60, Db Indust.-Comm.-Inst. Steam Gen. Units

References: 60.40b
60.42b
60.43b
60.45b
60.46b

Abstract:

Which Subpart, D or Db, applies if coal and oil are burned in combination? In combination with other fuels? Other fuels alone?

The source must comply with the particulate limits in both Subparts D and Db and must conduct a performance test firing 100% coal and then 100% oil. Both subparts have a 20% opacity limit.

For facilities constructed between the 1984 and 1986 applicability dates, the particulate standard in Subpart Db applies if the facility is coal fired. No NSPS Subpart applies to a oil fired unit of this size. For affected facilities that fire wood, the particulate standard at Section 60.34b(c) applies and those that fire municipal type waste are subject to the particulate standard at Section 60.43b (d).

For affected facilities that co-fire fuels, when the initial performance test is conducted, it is necessary that only one fuel be fired during each performance test.

Letter:

Control Number: NN06

December 27, 1990

4APT-AE

Mr. Lee A. Daniel, Jr., Chief
Air Quality Section
North Carolina Department of Environment,
Health, and Natural Resources
Division of Environmental Management
P.O. Box 27687
Raleigh, North Carolina 27611-7687

Dear Mr. Daniel:

As requested in your March 9, 1990 letter to Mr. Winston Smith, we are providing responses to your questions on 40 C.F.R. Part 60, Subpart Db. In our letter of April 26, 1990, we indicated that we would respond to your questions by May 15, 1990; however, we were unable to obtain interpretations from EPA Headquarters until this time. We apologize for any inconvenience and encourage your agency's development of a decision tree for Subpart Db. We would appreciate it if you would send a copy of the decision tree to us.

Your questions have been quoted and are followed by our responses:

Question 1: Section 60.40(b) addresses the issue of applicability for facilities constructed between June 19, 1984 and June 19, 1986. For the particulate limits, during this interim period, there is some overlap between Subpart D and Subpart Db, for facilities above 250 million Btu. There is overlap between SIP and Db facilities between 100 and 250 million Btu. The subpart or emission standard that applies depends on the fuel being used, the choices being coal and oil. This section makes no allowance for situations where coal and oil are burned in combination. We wish to know which subpart or standard applies if coal and oil re burned in combination. If some sort of prorating scheme is required, please supply the appropriate formula.

Response 1: The source must comply with the particulate limits in both Subparts D and Db and must conduct a performance test firing 100% coal and then 100% oil. Both subparts have a 20% opacity.

Question 2: How should applicability questions be addressed under 60.40b(b) for fuels other than coal and oil either fired alone or in combination (combinations which may include coal and/or oil)?

Response 2: For facilities constructed between the 1984 and 1986 applicability dates, the particulate standard in Subpart Db applies if the facility is coal fired. No NSPS standard applies for only oil fired units in this size range. For affected facilities that fire wood, the particulate standard at Section 60.43b(c) applies and those that fire municipal type waste are subject to the particulate standard at Section 60.43b(d).

For affected facilities that co-fire fuels, when the initial performance test is conducted, it is necessary that only one fuel be fired for each performance test. For example, if an affected facility can fire 100% coal or 100% industrial solid waste, the performance test must be conducted on 100% coal since Subpart Db does not have a standard for industrial solid waste.

Question 3: Should coal refuse not burned in a fluidized bed boiler or burned in combination with other fuels in a fluidized bed boiler be treated as coal?

Response 3: Yes, the definition of "Coal" in Subpart Db includes coal refuse.

Question 4: Please confirm whether or not the prorate formula in Section 60.42b(a) is appropriate for applying the emission factors given in Section 60.42b(d).

Response 4: No, the prorate formula is not applicable. The SO2 emission standards are fuel specific and no prorate formula applies. In order for a source owner or operator to comply with this standard, the boiler can not fire coal with a sulfur content which would result in SO2 emissions greater than 1.2 lb/mmBtu (based solely on the heat input from the coal) or oil with a sulfur content which would result in SO2 emission greater than 0.5 lb/mmBtu (based solely on the heat input from the oil). This type of oil is defined as "Very low sulfur oil" in Subpart Db.

Question 5: Is municipal-type solid waste considered a solid fuel within the context of Section 60.43b(a)(iii)?

Response 5: Yes, municipal-type solid waste is considered solid fuel for the purposes of Section 60.43b(a)(3)(iii).

Question 6: Section 60.43b(f) appears to contain an error. We believe that "paragraphs (a), (b), and (c) of this section" should read "paragraphs (a), (b), (c), and (d) of this section". Please confirm.

Response 6: Yes, the intent of the regulation is to have facilities which meet the criteria in paragraphs (a), (b), (c) and (d) of Section 60.43b. When Subpart Db was proposed on June 19, 1986 to include the particulate standard for oil burning facilities at Section 60.43b(b), they inadvertently did not revise Section 60.43b(f).

Question 7: Section 60.45b(c)(1) appears to contain a contradiction regarding the date on which the initial performance test is to be started.

Response 7: We interpret this section to mean that the initial performance test must be conducted within 60 days of reaching maximum production and no later than 180 days after initial start-up.

Question 8: Section 60.45b(c)(2) thru (c)(5) appear to offer no provisions for coal and oil burned in combination. How should such a combination firing be handled?

Response 8: In order to determine the proper compliance and performance test methods and procedures for SO2 under Subpart Db it is necessary to determine which SO2 emission standard in Section 60.42b applies. When a facility fires coal and oil in combination, there are three SO2 emission standards which could possibly apply:

1. The facility could be subject to Section 60.42b(a) which requires 90 percent reduction and limits SO2 emissions as determined by the prorate formula given. In this case, the procedures in Section 60.45b(c)(2) which reference Method 19 are used to determine compliance. See Section 3.3 of Method 19 which addresses fuels fired in combination.

2. The facility could be subject to Section 60.42b(c) which requires 50 percent reduction if an emerging SO2 control technology is used and limits SO2 emissions as determined by the prorate formula give. Once again, the procedures in Section 60.45b(c)(2) are used to determine compliance.

3. The facility could be subject to Section 60.42b(d) which limits SO2 emissions to 1.2 lb/mmbtu based solely on the heat input from the coal and SO2 emissions to 0.5 lb/mmBtu based solely

on the heat input from the oil. In addition, no percent reduction applies. The procedures used to determine compliance are specified in Section 60.45b(c)(5).

*

Question 9: Section 60.45b(c)(3)(ii) makes reference to (b)(3)(i). Sections 60.45b(c)(4) and 60.45b(c)(5) both make reference to paragraph (b)(3). It appears that these should read (c)(3) instead of (b)(3). Please confirm.

Question 9: Yes, your assumption is correct, Section 60.45(c)(3)(ii) should reference Section 60.45b(c)(3)(i). Section 60.45b(c)(4) and Section 60.45b(c)(5) should reference Section 60.45b (c)(3).

Question 10: Section 60.45b(e) makes reference to "capacity utilization rate". Is this the same as annual capacity factor?

Response 10: Yes, the "capacity utilization rate" is synonymous with annual capacity factor.

*

Question 11: In Section 60.46b(e)(5), should "paragraph (iii)" and "paragraph (iv)" read "paragraph (3)" and "paragraph (4)"?

Response 11: No, paragraphs (2) and (4) should be referenced.

Question 12: Is a slag tap furnace referenced in Subpart Db the same as a cyclone-fired unit reference in Subpart D?

Response 12: No, not all slag tap furnaces are cyclone-fired boilers but all cyclone-fired units are slag tap furnaces.

If you have any questions regarding this letter, please contact Mr. Paul Reinermann at 404-347-2904.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides and Toxics Management Division

PREINERMANN::psr:11/16/90:final:DISK No. 7:DOC No.:7-1dncdehnr FILE No.: 10.9.5b REINERMANN

Appendix B

Blaine Larsen Farms, Dubois

T2-030514

Modeling

MEMORANDUM

TO: Ken Hanna, Air Permit Analyst, Air Program Division
Mary Anderson, Air Modeling Coordinator, Air Program Division

FROM: Rick Hardy, Air Modeler, State Office of Technical Services

SUBJECT: Atmospheric Dispersion Modeling Review for the Larsen Farms PTC/Tier II Permit

DATE: February 12, 2004

1.0 SUMMARY:

The Department of Environmental Quality (DEQ) received a Permit to Construct Application from Blaine Larsen Farms, Inc. (BLF) for the purpose of allowing a fuel change to residual oil and other fuels. It was subsequently determined that a Tier II operating permit application would be required.

A technical review of the submitted air quality analysis was conduced by DEQs Technical Services Division. The modeling analyses, with the stated minor refinement: 1) utilized appropriate methods and models; 2) was conducted using proper model parameters and accurate input data; 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) demonstrated that predicted pollutant concentrations from facility-wide emissions, when combined with appropriate background concentrations, were below applicable air quality standards.

2.0 DISCUSSION:

2.1 Applicable Air Quality Impact Limits

This section identifies applicable ambient air quality limits and analyses used to evaluate the predicted ambient air quality impacts.

2.1.1 Area Classification

The BLF Facility is located in Clark County designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), and particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}). There are no Class I areas within 10 kilometers of the facility.

2.1.2 Full Impact Analyses

DEQ determined that a full impact analysis was necessary for this Tier II operating permit to demonstrate compliance with IDAPA 58.01.01.403.02. A full impact analysis for attainment area pollutants involves adding ambient impacts from facility-wide emissions to DEQ-approved background concentration values that are appropriate for the criteria pollutant/averaging-time at the facility location. The resulting maximum pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2.1. Table 2.1 also lists significant contribution levels and specifies the modeled value that is used for comparison to the NAAQS.

Table 2.1 APPLICABLE REGULATORY LIMITS

1. 2. 3. POLLUTANT	Averaging Period	Significant Contribution Levels[a] ($\mu g/m^3$)[b]	Regulatory Limit[c] ($\mu g/m^3$)	Modeled Value Used[d]
PM_{10}[e]	Annual	1.0	50[f]	Maximum 1[st] highest[g]
	24-hour	5.0	150[h]	Maximum 2[nd] highest[i]
Carbon monoxide (CO)	8-hour	500	10,000[j]	Maximum 2[nd] highest[g]
	1-hour	2,000	40,000[j]	Maximum 2[nd] highest[g]
Sulfur Dioxide (SO_2)	Annual	1.0	80[f]	Maximum 1[st] highest[g]
	24-hour	5	365[j]	Maximum 2[nd] highest[g]
	3-hour	25	1,300[j]	Maximum 2[nd] highest[g]
Nitrogen Dioxide (NO_2)	Annual	1.0	100[f]	Maximum 1[st] highest[g]
Lead (Pb)	Quarterly	NA	1.5[j]	Maximum 1[st] highest[g]

a. IDAPA 58.01.01.006.93
b. Micrograms per cubic meter
c. IDAPA 58.01.01.577 for criteria pollutants
d. The maximum 1[st] highest modeled value is always used for significant impact analysis, however the high-2[nd] high value is used for short-term standards in the full impact analysis.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal ten micrometers
f. Never expected to be exceeded in any calendar year
g. Concentration at anqy modeled receptor
h. Never expected to be exceeded more than once in any calendar year
i. Concentration at any modeled receptor when using one year of meteorological data. When 5 years of meteorology is used, DEQ guidance allows for use of the highest 6[th] high PM_{10} concentration.
j. Not to be exceeded more than once per year

2.1.3 Toxic Air Pollutant Impact Analysis

An ambient air assessment of Toxic Air Pollutant (TAP) impacts conducted by the applicant for the PTC portion of this permit, per DEQ's Air Program Division, for the facility to demonstrate compliance with IDAPA 58.01.01.161. The Tier II modeling analysis was conducted only for criteria pollutants

2.2 Background Concentrations

Background concentrations were revised for all areas of Idaho by DEQ in March 2003[1]. Background concentrations in areas where no monitoring data are available were based on monitoring data from areas with similar population density, meteorology, and emissions sources. Background concentrations for rural/agricultural areas were used for the BLF facility. Table 2.2 lists the rural/agricultural default background concentrations.

Table 2.2 BACKGROUND CONCENTRATIONS

4. POLLUTANT	Averaging Period	Background Concentration ($\mu g/m^3$)[a]
PM_{10}[b]	24-hour	73
	Annual	26
Carbon monoxide (CO)	1-hour	3,600
	8-hour	2,300
Sulfur dioxide (SO_2)	3-hour	34
	24-hour	26
	Annual	8
Nitrogen dioxide (NO_2)	Annual	17
Lead (Pb)	Quarterly	0.03

a. Micrograms per cubic meter
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers

1 Hardy, Rick and Schilling, Kevin. *Background Concentrations for Use in New Source Review Dispersion Modeling*. Memorandum to Mary Anderson, March 14, 2003.

2.3 *Modeling Impact Assessment*

Table 2.3 provides a summary of the modeling parameters used in the submitted modeling section of the application. For DEQ's verification analyses, the same parameters were used except that the outer receptor grids were deleted to reduce run times after verifying that maximum impacts all occurred within the 125 meter wide fence line grid (Grid 1).

Table 2.3 MODELING PARAMETERS

Parameter	Description/Values	Documentation/Additional Description
Model	ISC3	Version 02035
Meteorological data	Pocatello Surface Data Boise Upper Air Data	1987-1991
Model options	Regulatory Default	
Land use	Rural	Low population density in area and large fraction of unimproved land
Terrain	Flat	All elevation set to 0.0
Building downwash	Used building profile input program for ISCST3 (BPIP)	Building dimensions obtained from modeling files submitted
Receptor grid	Grid 1	25-meter spacing along boundary out to 125 meters
	Grid 2	100-meter spacing out to about 1600 meters
	Grid 3	500 meter spacing out to 10-15 km
	DEQ verified maximum values are within Grid1, then deleted Grids 2 and 3 to improve run times.	
Facility location (UTM)[a]	Easting	402475.0 meters
	Northing	4881825.0 meters

a. Universal Transverse Mercator

2.3.1 Modeling protocol

A modeling protocol was submitted to DEQ on April 18, 2003.

2.3.2 Model Selection

Ambient air impact analyses were performed by JBR, BLF's consultant, using the model ISCST3, version 02035. DEQ concurs with JBR selection of ISCST3 for these dispersion-modeling analyses.

2.3.3 Land Use Classification

Well over 50% of the land use of the surrounding area is rural. Therefore, rural dispersion coefficients were used in the modeling analyses.

2.3.4 Meteorological Data

Surface meteorological data from Pocatello, Idaho for 1988-1991 and upper air data for Boise, Idaho, for the same period, were used in the modeling analyses. DEQ determined these data are the most representative data currently available for the area.

2.3.5 Complex Terrain

The modeling analyses submitted included actual terrain elevations for both sources and receptors. A review of the topographical location map verifies that a flat terrain assumption is adequate for this area and that the elevations assigned to each source and receptor appear to be appropriate.

2.3.6 Facility Layout

DEQ verified proper identification of the facility boundary and buildings on the site by comparing the modeling input to a facility plot plan submitted with the application.

2.3.7 Building Downwash

Buildings are relatively short and squat and far enough from the property line so that plume downwash effects caused by structures present at the facility were adequately accounted for in the modeling analyses without using the Prime version of the ISCST3 model.

2.3.8 Ambient Air Boundary

The applicant used fence lines of the facility as the boundary to ambient air, as described in the modeling protocol.

2.3.9 Receptor Network

JBR used a receptor grid consisting of 25-meter spacing along the fence line out to a distance of 125 meters in the areas of maximum impact, a 100-meter grid beyond that out to approximately 1600 meters and a 500-meter grid, typically out 10 – 15 km. The same grid was used by DEQ without alteration, except that once it was verified that maximums always occur within the 125-meter wide fence line grid (with a 25 meter spacing), the 250 and 500-meter outer grids were dropped to reduce run times.

2.3.10 Emissions Rates

Emissions rates used in the dispersion modeling analyses submitted by the applicant were reviewed against those in the permit application, the engineering technical memorandum, and the proposed permit. The following approach was used in the submitted files, updated December 16, 2003 and January 16 with revised modeling files having optional stack parameters (as discussed below).

Modeling for SO_2 and NO_2 was not revised as the predicted concentrations for these pollutants were well below the standards and the revised stack parameters would only act to further lower the impacts.

- All modeled emissions rates were equal to the facility's submitted short-term emissions rates as presented in the submitted modeling files. Short term emissions rates were used for all pollutants for all averaging periods, assuming 8760 hours of operation, including the boiler emissions for scenarios identified as operating only 7000 hours per year. This approach is conservative and does not affect the 24-hour PM_{10} calculation which is the standard which comes closest to being exceeded. Thus, the annual PM_{10} modeling is conservative.

- Modeling results were compared to *significant contribution* thresholds by JBR. Then all pollutants were treated in a full impact analysis. Carbon monoxide (CO) and lead (Pb) were reported to be below significant contribution levels in the submittal. JBR submitted full impact analysis for carbon monoxide, but not lead. DEQ checked the significant impact determination but did not verify the carbon monoxide or lead full impact analysis.

- The original SO_2 modeling did not include SO_2 contributions from sulfite in the drying processes. The January 13, 2004 submittal reported these emissions but did not include revised modeling for SO_2. However, SO_2 from sulfite oxidation totals only 0.21 lb/hr or 0.3% of the total SO_2 emissions from all sources. Since the maximum SO_2 impacts are well below the NAAQS, there is no need to revise the modeling to reflect these emissions.

Table 2.4 provides criteria pollutant emissions quantities used for both short-term and long-term averaging periods. TAPs emissions rates used in the modeling analysis, as submitted January 13, 2004 (in revised modeling files with modified stacks), are shown in Table 2.5. The specific TAPS included in Table 2.5 represent those whose emissions exceed the TAPs emissions screening levels (ELs) established in IDAPA 58.01.01 585 and 586. The TAPs screening analysis is provided in the Emissions Inventory report.

Table 2.4 CRITERIA POLLUTANT EMISSIONS RATES USED FOR MODELING (SHORT-TERM &LONG-TERM)

Source / Id Code	Rate Used for Modeling (lb/hr)[b]				
	PM_{10}[c]	Carbon Monoxide	Nitrogen Dioxide	Sulfur Dioxide[e]	Lead
BOILER_1	8.29	11.86	41.81	69.8	N/A
NAT_A1	0.97	0.30	0.55	0.060	N/A
NAT_A2	0.97	0.30	0.55	0.060	N/A
NAT_B	0.97	0.30	0.55	0.060	N/A
NAT_C	0.97	0.30	0.55	0.060	N/A
REC_1	0.010	0.11	0.25	0.020	N/A
REC_2	0.010	0.11	0.25	0.020	N/A
REC_3	0.010	0.11	0.25	0.020	N/A
FBD_DYR	0.760	0.38	0.67	0.070	N/A
FP_BULK	0.065	N/A	N/A	N/A	N/A
FP	0.032	N/A	N/A	N/A	N/A
FP_TOR	0.430	N/A	N/A	N/A	N/A
FP_BH	0.097	N/A	N/A	N/A	N/A
DRUM1	0.290	N/A	N/A	N/A	N/A
DRUM3	0.290	N/A	N/A	N/A	N/A
DRUM5	0.290	N/A	N/A	N/A	N/A
DRUM2	0.290	N/A	N/A	N/A	N/A
DRUM4	0.290	N/A	N/A	N/A	N/A
DRUM6	0.290	N/A	N/A	N/A	N/A
DRUM7	0.290	N/A	N/A	N/A	N/A
DRUM8	0.290	N/A	N/A	N/A	N/A
DRUM9	0.290	N/A	N/A	N/A	N/A
DRUM10	0.290	N/A	N/A	N/A	N/A
DRUM11	0.290	N/A	N/A	N/A	N/A
DRUM12	0.290	N/A	N/A	N/A	N/A

a. Universal Transverse Mercator
b. Pounds per hour
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
d. Short-term rate listed in originally submitted application.
e. Does not include revised SO_2 emissions reported in the submittal dated January 13, 2004.

Table 2.5 TOXIC AIR POLLUTANTS EMISSIONS RATES MODELED

Source ID	Toxic Air Pollutant Emissions Rates (lb/hour)[a]								
	As	Be	Cd	Cr	Co	HCHO	Ni	PAH	P
BOILER_1	1.17E-03	4.00E-04	4.00E-04	2.20E-04	5.35E-03	2.93E-02	3.0E-04[b]	1.40E-05	8.41E-03
NAT_A1	7.20E-07	4.30E-08	4.00E-06	N/A	3.00E-07	2.74E-04	7.60E-06	4.05E-08	N/A
NAT_A2	7.20E-07	4.30E-08	4.00E-06	N/A	3.00E-07	2.74E-04	7.60E-06	4.05E-08	N/A
NAT_B	7.20E-07	4.30E-08	4.00E-06	N/A	3.00E-07	2.74E-04	7.60E-06	4.05E-08	N/A
NAT_C	7.20E-07	4.30E-08	4.00E-06	N/A	3.00E-07	2.74E-04	7.60E-06	4.05E-08	N/A
REC_1	2.40E-07	1.40E-08	1.30E-06	N/A	1.00E-07	9.00E-05	2.50E-06	1.40E-08	N/A
REC_2	2.40E-07	1.40E-08	1.30E-06	N/A	1.00E-07	9.00E-05	2.50E-06	1.40E-08	N/A
REC_3	2.40E-07	1.40E-08	1.30E-06	N/A	1.00E-07	9.00E-05	2.50E-06	1.40E-08	N/A
FBD_DYR	9.00E-07	5.40E-08	5.00E-06	N/A	3.80E-07	3.40E-04	9.50E-06	5.10E-08	N/A

a. As is arsenic, Be is Beryllium, Cd is cadmium, Cr is chromium VI, HCHO is Formaldehyde, Ni is Nickel, PAH refers to poly-aromatic hydrocarbons, and P is phosphorous.
b. Nickel emissions submitted by the applicant for the boiler (3.0E-04 lb/hr) were based on natural gas.
c. All modeling assumes 8760 hours per year operation.

2.3.11 Emissions Release Parameters

Table 2.6 provides emissions release parameters, including stack location, stack height, stack diameter, exhaust temperature, and exhaust velocity. Parameters are as listed in the final DEQ verification modeling runs, unless modified by DEQ and discussed in this section and Section 2.3.12. Horizontal releases and stacks with rain caps were given velocities of 0.001 m/s and in some cases, diameters of 0.001 m appropriate for a horizontally directed release.

"Hour-of-Day" scalars were not used for any sources so the facility was modeled consistent with a 24 hour-per-day operation.

It should be noted that the stack parameters in the revised modeling description (received December 16, 2003) differs from the final submitted electronic modeling files received December 16, 2003 and DEQ verification runs in the following manner:

- The text says 20 feet will be added to the Boiler stack, however the height of that stack in the modeling files was 13.72 m or 45.0 feet, only 10 feet higher than the original submittal. DEQ did not change the submitted height in our verification modeling.

- The text says drum dryers will be raised an additional 10 feet. The submitted modeling files treated the drum dryers as 45.6 feet (13.89 m), no change from the original submittal. DEQ did not change drum dryer stack heights in the verification modeling.

- For the National Dryer stacks, the modeling is in agreement with the text submitted on December 16, 2003 as "Option 3". It is repeated here for clarity. The text says the National Dryer stacks will be converted from a horizontal to a vertical discharge and will be raised 10 feet. The modeled stacks in the submitted modeling were 46.0 feet (14.02 m) or 10 feet higher than in the original submittal. The National Dryer stacks were modeled as vertical discharges with no cap. No change was made in the DEQ verification modeling.

- Finally, an unusually high stack velocity for the FP Bulk Baghouse, 326 feet per second (fps) was modeled in the submitted files. The DEQ Program Office verified that the actual stack velocity is 79.2 fps and the diameter is 0.67 feet. The final DEQ verification modeling for the high-6th-high 24-hour PM_{10} and annual average incorporated these corrections.

2.3.12 Modeling Approach

The applicant submitted emissions rates for a variety of alternative fuels, including propane, natural gas, no. 2 diesel fuel and "very low sulfur" residual fuel. The modeling approach followed by the applicant and DEQ in the verification modeling was to select the highest emissions rate for each pollutant from amongst all the fuels. The stack parameters for residual oil, the fuel with the worst-case emissions rate for PM_{10} and SO_2 were used.

In addition, the modeling approach presented in the permit application utilized short-term emissions rates for all sources including the Boiler. This is conservative. The initial modeling submittal, dated May 19, 2003 included modeling analyses for PM_{10}, SO_2, CO, NO_2, and Toxic Air Pollutants. Subsequent revisions included an October 31, 2003 package with revised emissions rates, a December 2, 2003 submittal with revised PM10 modeling to reflect the October 31, 2003 emissions inventory, a December 12, 2003 submittal (received December 16, 2003) with "Option 3" modeling files to raise the stacks on the Boiler and the National Dryers as described above under *Emissions Release Parameters*; and a January 13, 2004 submittal with revised TAPs modeling to reflect the revised release parameters as submitted December 12, 2003.

DEQ verification modeling differed from the submitted files in the following ways:

- Outer receptors were stripped away to reduce run times, since the maximum impacts were verified to be well within the inner most receptor band.

- The FP Bulk Line baghouse stack parameters were corrected as discussed above (79.2 fps velocity and a 0.67 foot diameter were used) in an email from JBR to Ken Hanna.

- The highest 6[th]-high 24-hour PM_{10} concentration in 5 years was computed. The highest 2[nd] high value determined by JBR for each of the 5 years is conservative, however, DEQ guidance allows the highest 6[th] high value in 5 years.

- Emissions certified by Mr. Blaine Larsen and shown in Table 2.5-1 of that submittal, received January 16, 2004 did not match the submitted modeling files, in that process and combustion emissions are shown for the National Dryer sources, but only the combustion sources are shown. Since the values shown in the table were known to be correct and were certified, the PM_{10} modeling was modified by DEQ to include process (0.94 lb/hr for each National Dryer) plus combustion emissions (0.03 lb/hr each).

Table 2.6 EMISSIONS POINT LOCATIONS AND STACK PARAMETERS

Release Point	Source ID	UTM X	UTM Y	Stack Height (m)[a]	Modeled Diameter (m)	Stack Gas Temp. (K)[b]	Stack Gas Flow Velocity (m/sec)[c]
Boiler	Boiler_1	402339	4881756	13.72	2.03	580.4	8.69
Drum Dryer 1	Drum1	402391	4881771	13.89	1.09	324.8	0.001
Drum Dryer 2	Drum2	402382	4881765	13.89	1.09	324.8	0.001
Drum Dryer 3	Drum3	402382	4881775	13.89	1.09	324.8	0.001
Drum Dryer 4	Drum4	402391	4881780	13.89	1.09	324.8	0.001
Drum Dryer 5	Drum5	402382	4881769	13.89	1.09	324.8	0.001
Drum Dryer 6	Drum6	402382	4881778	13.89	1.09	324.8	0.001
Drum Dryer 7	Drum7	402382	4881783	13.89	1.09	324.8	0.001
Drum Dryer 8	Drum8	402372	4881765	13.89	1.09	324.8	0.001
Drum Dryer 9	Drum9	402372	4881769	13.89	1.09	324.8	0.001
Drum Dryer 10	Drum10	402372	4881775	13.89	1.09	324.8	0.001
Drum Dryer 11	Drum11	402372	4881778	13.89	1.09	324.8	0.001
Drum Dryer 12	Drum12	402372	4881783	13.89	1.09	324.8	0.001
National Dryer Fan A1	Nat_A1	402353	4881754	14.02	0.87	338.7	5.83
National Dryer Fan A2	Nat_A2	402358	4881754	14.02	0.87	353.1	5.83
National Dryer Fan B	Nat_B	402370	4881754	14.02	0.87	348.1	5.98
National Dryer Fan C	Nat_C	402380	4881754	14.02	0.87	337.6	5.98
Flake Packaging Bulk Line	FP_Bulk	402406	4881741	11.81	0.20[d]	0.0	24.1[d]
Flake Packaging	FP	402395	4881758	12.07	1.22	0.0	5.66
Flake PackagingTorit	FP_TOR	402410	4881751	10.34	0.08	0.0	0.001
Propane Heater 1	REC_1	402330	4881798	10.78	0.12	305.4	0.001
Propane Heater 2	REC_2	402345	4881790	10.54	0.12	305.4	0.001
Propane Heater 3	REC_3	402352	4881783	10.84	0.12	305.4	0.001
Fluidized Bed Dryer	FBD_DYR	402357	4881745	11.28	0.001	316.5	0.001
Flake Packaging Baghse	FP_BH	402410	4881756	11.41	0.47	0.0	33.01

a. Meters
b. Kelvin
c. Meters per second. Sources with velocity equal to 0.001 m/s are modeled as horizontal releases.
d. Revised from JBR's submitted modeling per email correction.

3.0 MODELING RESULTS:

This Section describes dispersion modeling results from the full impact analysis verification runs made by DEQ using the submitted electronic files with the exceptions noted in Sections 2.3.11 and 2.3.12. The applicant's original analysis is presented in the permit application and it's updates.

The applicant's contractor, JBR, conducted a Radius of Impact analysis and a Full Impact Analysis for all pollutants and presents results in the permit application. Results of the DEQ verification modeling of the full impact analysis are presented in Table 3.1 and Table 3.2. The lead and CO concentrations were below significant impact levels, so DEQ did not include them in its verification modeling. When added to the appropriate background levels, all pollutant ambient impacts were below the NAAQS.

A source contribution analysis was developed for PM_{10}, shown in Table 3.3, to provide an understanding of relative source impacts to the ambient PM_{10} levels. The boiler, fluidized bed dryer and Flake Packaging Torit have the greatest impacts, with 10.9, 9.8 and 9.1% contribution respectively.

Toxic Air Pollutant (TAPs) concentrations are presented in Table 3.4. In accordance with IDAPA 58.01.01 585 and 586, annual average concentrations are compared to the Acceptable Ambient Carcinogenic Concentration (AACC) for arsenic, beryllium, cadmium chromium VI, formaldehyde, nickel, total PAHs (poly-aromatic hydrocarbons) to assess carcinogenic health effects, while the 24-hour highest concentrations in any year are compared to the Acceptable Ambient Concentrations (AAC) to assess acute health effects. None of the TAPs exceed the established ambient air criteria.

Table 3.1 CRITERIA POLLUTANT DESIGN CONCENTRATIONS FOR FULL IMPACT ANALYSIS

Pollutant	Averaging Period	Design Basis	Design Concentration ($\mu g/m^3$)[a]	Receptor Location UTM[b]	
				Easting (m)[c]	Northing (m)
PM_{10}[d]	24-hour	6th high	74.4	402475	4881900
	Annual	1st high	20.9	402475	4881825
Carbon monoxide (CO)[f]	1-hour	2nd high	N/A	N/A	N/A
	8-hour	2nd high	N/A	N/A	N/A
Sulfur dioxide (SO_2)[e]	3-hour	2nd high	703	402475	4881800
	24-hour	2nd high	269	402475	4881825
	Annual	1st high	24.2	402475	4881825
Nitrogen dioxide (NO_2)[f]	Annual	1st high	26.8	402475	4881825
Lead (Pb)[f]	Quarterly	N/A	N/A	N/A	N/A

a. Micrograms per cubic meter
b. Universal Transverse Mercator
c. Meters
d. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
e. CO and Pb were below significance levels and were not verified in DEQ modeling.
f. Results for SO_2 and NO_2 are based on original stack parameters before boiler and dryer stack heights were
revised to provide greater plume rise. Thus the predicted values shown in Tables 4.1 and 4.2 are conservative.

Table 3.2 CRITERIA POLLUTANT TOTAL AMBIENT CONCENTRATION

Pollutant	Averaging Period	Total Ambient Impact[a] ($\mu g/m^3$)[b]	Background Concentration ($\mu g/m^3$)	Total Ambient Concentration ($\mu g/m^3$)	NAAQS[c] ($\mu g/m^3$)	Percent of NAAQS
PM_{10}[d]	24-hour	74.4	73	147.4	150	98.2%
	Annual	20.7	26	46.7	50	93.4
Carbon monoxide (CO)	1-hour	N/A	N/A	N/A	10,000	N/A
	8-hour	N/A	N/A	N/A	40,000	N/A
Sulfur dioxide (SO_2)	3-hour	702.7	34	736.7	1,300	56.6
	24-hour	268.9	26	294.9	365	80.8
	Annual	24.2	8	32.2	80	40.2
Nitrogen dioxide (NO_2)	Annual	26.8	17	43.8	100	43.8
Lead	Quarterly	N/A	N/A	N/A	1.	N/A

a. Based on model predictions
b. Micrograms per cubic meter
c. National Ambient Air Quality Standards
d. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers

Table 3.3 PM10 SOURCE CONTRIBUTION TO 24 HOUR PM_{10} IMPACTS

Source / Id Code	24-hour PM_{10}[a] High-6th High Concentration ($\mu g/m^3$)[b]	Percent Contribution To Ambient Impact
BOILER_1	11.48097	10.9%
DRUM1	3.99569	3.8%
DRUM3	3.48761	3.3%
DRUM5	3.38258	3.2%
DRUM2	4.10552	3.9%
DRUM4	3.37477	3.2%
DRUM6	3.50821	3.3%
DRUM7	3.71562	3.5%
DRUM8	3.13159	3.0%
DRUM9	3.18607	3.0%
DRUM10	3.26899	3.1%
DRUM11	3.30769	3.1%
DRUM12	3.19023	3.0%
NAT_A1	7.52421	7.1%
NAT_A2	6.90169	6.5%
NAT_B	7.23878	6.9%
NAT_C	7.56374	7.2%
FP_BULK	1.10997	1.1%
FP	0.4731	0.4%
FP_TOR	9.6111	9.1%
REC_1	0.26603	0.3%
REC_2	0.2712	0.3%
REC_3	0.22743	0.2%
FBD_DYR	10.35037	9.8%
FP_BH	0.91161	0.9%

a. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
b. Micrograms per cubic meter

Table 3.4 TOXIC AIR POLLUTANT ANALYSIS RESULTS

Pollutant	Year	Highest Annual Impact (μg/m³)	AACC[a] (μg/m³)[b]	Percent of AACC?	Receptor Location (UTM)[c]	
					Easting (m)[d]	Northing (m)
Arsenic	1989	1.2E-04	2.3E-04	52%	402475	4881825
Beryllium	1989	4.0E-05	4.2E-03	1%	402475	4881825
Cadmium	1989	1.2E-04	5.6E-04	21%	402475	4881825
Chromium VI	1989	2.0E-05	8.3E-05	24%	402475	4881825
Formaldehyde	1989	8.47E-03	7.7E-02	11%	402475	4881825
Nickel	1989	1.7E-04	4.2E-03	4%	402475	4881825
PAHs	1989	0.12E-05	1.4E-02	0.0086%	402475	4881825
Pollutant	**Year**	**High-2nd High 24 Hour Impact (μg/m³)**	**AAC[a] (μg/m³)[b]**	**Percent of AAC?**	**Receptor Location (UTM)[c]**	
					Easting (m)[d]	**Northing (m)**
Cobalt[e]	1989	0.0108	2.5	0.54%	402317	4882000
Phosphorous	1989	0.017	5.0	0.3%	402317	4882000

a. Acceptable ambient concentration for carcinogens
b. Micrograms per cubic meter
c. Universal Transverse Mercator
d. Meters
e. Vanadium was addressed by scaling the cobalt results in the Statement of Basis.

4.0 FILES

Electronic copies of the modeling analysis are saved on disk. Table 4.5 provides a summary of the files used in the modeling analysis. The Permit Writer has reviewed this modeling memo to ensure consistency with the PTC and technical memorandum.

Table 4.5 DISPERSION MODELING FILES

Type of File	Description	File Name
Met data	Surface data from Pocatello, Idaho Upper air data from Boise, Idaho NWS data: January 1987 – December 1991	POCXXadj.MET XX = year of met data
BEEST input files	Short term	*.BST
	Annual	*.BST
Each BST file has the following type of files associated with it:		
	Input file for BPIP program	.PIP
	BPIP output file	.TAB
	Concise BPIP output file	.SUM
	BEE-Line file containing direction specific building dimensions	.SO
	ISCST3 input file for each pollutant	.DTA
	ISCST3 output list file for each pollutant	.LST
	User summary output file for each pollutant	.USF
	Master graphics output file for each pollutant	.GRF
Some modeling files have the following type of graphics files associated with them:		
	Surfer data file	.DAT
	Surfer boundary file	.BLN
	Surfer post file containing source locations	.TXT
	Surfer plot file	.SRF

G:\Technical Services/Modeling/Hardy/NSR/BLF/BLF Modeling Memo 2-12-04 Final.doc

RH:sl

Appendix C

Blaine Larsen Farms, Dubois

T2-030514

AIRS Table

BLAINE LARSEN FARMS TIER II/PTC

AIRS/AFS[a] FACILITY-WIDE CLASSIFICATION[b] DATA ENTRY FORM

AIR PROGRAM / POLLUTANT	SIP	PSD	NSPS (Part 60)	NESHAP (Part 61)	MACT (Part 63)	TITLE V	AREA CLASSIFICATION A – Attainment U – Unclassifiable N – Nonattainment
SO_2	A		A			A	U
NO_x	A		A			A	U
CO							U
PM_{10}							U
PT (Particulate)							U
VOC							
THAP (Total HAPs)							
			APPLICABLE SUBPART				
			Db	none	none		

[a] Aerometric Information Retrieval System (AIRS) Facility Subsystem (AFS)

[b] AIRS/AFS Classification Codes:

A = Actual or potential emissions of a pollutant are above the applicable major source threshold. For NESHAP only, class "A" is applied to each pollutant which is below the 10 T/yr threshold, but which contributes to a plant total in excess of 25 T/yr of all NESHAP pollutants.

SM = Potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable regulations or limitations.

B = Actual and potential emissions below all applicable major source thresholds.

C = Class is unknown.

ND = Major source thresholds are not defined (e.g., radionuclides).

Appendix D

Blaine Larsen Farms, Dubois

T2-030514

Response to Comments

April 13, 2004

STATE OF IDAHO
DEPARTMENT OF ENVIRONMENTAL QUALITY
RESPONSE TO PUBLIC COMMENTS
ON THE PROPOSED TIER II OPERATING PERMIT AND PERMIT TO CONSTRUCT
FOR THE BLAINE LARSEN FARMS DEHYDRATION DIVISION, DUBOIS, IDAHO

Introduction

As required by IDAPA 58.01.01.209 and 404 of the *Rules for the Control of Air Pollution in Idaho* (*Rules*), the Idaho Department of Environmental Quality (DEQ) provided for public notice and comment on the proposed permit to construct for the Blaine Larsen Farms, Inc. Dehydration Division facility located near Dubois, Idaho. Public comment packages, which included the application materials, the permit, and associated statement of basis, were made available for public review at the Clark County Public Library in Dubois, and the DEQ's State Office in Boise and Regional Office in Pocatello. The public comment period was provided from March 11, 2003 through April 12, 2004. Written comments were received. Those comments regarding the air quality aspects of the permit are paraphrased below with DEQ's response immediately following.

Public Comments and DEQ Responses

Responses to the comments received from Blaine Larsen Farms, Inc. on March 9, 2004 are provided below. All permit condition numbers given below refer to the numbers in the proposed permit, not the final permit, unless noted otherwise.

Comment 1: **Where is Permit Condition 1.2?**

Response to 1: The Permit Conditions in Section 1 of the permit were re-numbered.

Comment 2: **This section [Permit Condition 3.4, 40 CFR 60.42b(a)] is not needed when burning very low sulfur fuel only. Is this section [Permit Condition 3.5, 40 CFR 60.42b(e)] needed? Larsen Farms will comply with 60.42b(j)(2), maintaining fuel receipts. Also, regarding Permit Condition 3.15, which establishes a 0.5% sulfur limit for fuel oil, it is stated that "this obviates the need for some above sections as noted."**

Response to 2: These comments affect numerous permit conditions regarding the SO_2 standards under NSPS Subpart Db. Details regarding each affected permit condition are provided below. DEQ requested clarification of the SO_2 requirements from EPA Region 10 on April 6, 2004, therefore, the regulatory positions may change after issuance of the permit.

Permit Condition 3.4 was changed to delete the part of 60.42b(a) which states "...any gases that contain sulfur dioxide in excess of 10 percent (0.10) of the potential sulfur dioxide emission rate (90 percent reduction)..." This is consistent with 60.42b(j) which states "Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil." It is noted that Permit Condition 3.15 limits the fuel sulfur content to 0.5% by weight which meets the definition given by 60.41b for "very low sulfur oil."

Permit Condition 3.5 is necessary since 40 CFR 60.42b(e) applies.

Permit Condition 3.17 was changed to state "(2) Maintaining fuel receipts as described in 40 CFR 60.49b(r)." Permit Condition 3.18 was changed in a similar way to state "In accordance with 40 CFR 60.49b(r) and as specified by the EPA,..." These changes were made to accommodate the pending regulatory decision from EPA Region 10 regarding applicability of the Subpart Db SO_2 requirements for this boiler.

Permit Condition 3.20 was re-arranged to be more consistent with 3.18 and 3.27; it was not substantively changed. These changes were also made to accommodate the pending regulatory decision from EPA Region 10 regarding applicability of the Subpart Db SO_2 requirements for this boiler.

Permit Condition 3.28 was changed to clarify why records must be maintained for five years instead of two; this is required for a Tier II operating permit. This will also be necessary under the pending Tier I operating permit.

Permit Condition 3.33 was changed to provide a direct reference to Permit Condition 3.27. This makes applicability of initial performance test requirements more clear for SO_2.

The first sentence of Permit Condition 3.37 was changed to accommodate the pending EPA applicability determination. This condition was not removed from the permit because it may or may not apply, depending on whether or not fuel receipts are used. However additional information was added to the Statement of Basis regarding the reporting requirements under 60 49b(j) so it will be more clear when reporting is necessary and when it is not. Permit Condition 3.37.3 was deleted because 60.49b(n) is not applicable. 60.49b(n) is not applicable because the SO_2 percent reduction requirements are not applicable per 60.42b(j), and this is because the permit requires only very low sulfur fuel oil to be used.

Permit Condition 3.38 was changed to accommodate the pending EPA applicability determination regarding fuel receipt requirements for residual oil.

Comment 3: **Is this lead in necessary [i.e., the phrase "Except as provided under 40 CFR 60.44b(l)" in Permit Condition 3.8]?**

Response to 3: The lead in phrase to Permit Condition 3.8 is not necessary and it was deleted because 40 CFR 60.44b(l) does not apply. 60.44b(l) does not apply since construction of the Wabash Boiler commenced prior to July 9, 1997. For this reason, Permit Condition 3.10 in the draft permit was also deleted.

Comment 4: **Please delete Permit Condition 3.9. Mixtures will not be combusted simultaneously.**

Response to 4: Permit Condition 3.9 was deleted as requested. This condition had been included in the draft permit since it was not known at that time if fuel mixtures would be combusted simultaneously. If Larsen Farms chooses to combust fuel mixtures simultaneously at some time in the future, then 40 CFR 60.44b(b) will apply.

Comment 5: **Are [Permit Conditions 3.8, 9, and 10] referring to low heat release necessary? *Low heat release rate* means a heat release rate of 70,000 Btu/hr-ft^3 or less. Boiler specs show the following heat release in Btu/hr-ft^3: Natural Gas, 77,600; Diesel, 73,900; #6 Oil, 73,400.**

Response to 5: As a result of this comment, DEQ now has information which specifies the heat release rates of the Boiler. Permit Condition 3.8 was changed as requested to include only emission rate standards for the "high heat release rate" category. Permit Conditions 3.9 and 3.10 were deleted.

application, the maximum amount of fuel oil burned in the Boiler would be 889 gal/hr, and the amount per day is then: (889 gal/hr)(24 hr/day) = 21,336 gal/day.

Comment 7: **With regard to Permit Condition 3.19 in the draft permit, can fuel testing (per batch, for example) be done as an option?**

Response to 7: The permit condition was changed as requested to provide an option for sampling and analysis. The first bullet item was also changed to refer specifically to ASTM grade 1 and 2 fuel oil to avoid any conflict between the residual oil sulfur content (i.e., 1.75%) allowed by IDAPA 58.01.01.727-728 and the 0.5% limit established in the permit. Note that for residual oil, monitoring is addressed by the NSPS under 60.42b(j) in permit condition 3.18.

Comment 8: **Please remove Permit Condition 3.23 regarding applicability of 60.49b(e).**

Response to 8: Permit condition 3.23 was not removed, however, it was changed to accommodate the pending EPA applicability determination for 60.46b. In particular, on April 6, 2004 DEQ asked EPA Region 10 what " the criteria under 60.46b(e)(4)" means. Also, Permit Condition 3.29.2 was changed. This is because page 19 of the application indicates the facility will use residual fuel with a nitrogen content of 0.15%. Since this is below 0.30 weight percent then 60.46b(e)(4) will apply instead of 60.46b(e)2). Since it remains a possibility that the fuel supplier could be changed in the future such that the residual fuel oil nitrogen content exceeds 0.3%, 60.46b(e)(2) would apply in that case. Therefore, permit condition 3.29.2 was left in the permit but it was shortened for streamlining purposes.

Comment 9: **Permit Condition 3.34 won't apply but it may be left in the permit.**

Response to 9: Larsen Farms has indicated that at NO_x CEMS will be used to meet the NO_x monitoring requirements of 60.46b. Since use of a predictive monitoring system is still a viable future option for the facility, this requirement was left in the permit. However, it was revised so it's that this applies only in the event that a CEMS is not used.